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MISSION STATEMENT

The mission of Energy Regulation Quarterly (ERQ) is to provide a forum for debate and discussion on issues surrounding the regulated energy industries in Canada, including decisions of regulatory tribunals, related legislative and policy actions and initiatives and actions by regulated companies and stakeholders. The role of the ERQ is to provide analysis and context that go beyond day-to-day developments. It strives to be balanced in its treatment of issues.

Authors are drawn from a roster of individuals with diverse backgrounds who are acknowledged leaders in the field of energy regulation. Other authors are invited by the managing editors to submit contributions from time to time.

EDITORIAL POLICY

The ERQ is published online by the Canadian Gas Association (CGA) to create a better understanding of energy regulatory issues and trends in Canada.

The managing editors will work with CGA in the identification of themes and topics for each issue. They will author editorial opinions, select contributors, and edit contributions to ensure consistency of style and quality. The managing editors have exclusive responsibility for selecting items for publication.

The ERQ will maintain a "roster" of contributors and supporters who have been invited by the managing editors to lend their names and their contributions to the publication. Individuals on the roster may be invited by the managing editors to author articles on particular topics or they may propose contributions at their own initiative. Other individuals may also be invited by the managing editors to author articles on particular topics.

The substantive content of individual articles is the sole responsibility of the respective contributors. Where contributors have represented or otherwise been associated with parties to a case that is the subject of their contribution to ERQ, notification to that effect will be included in a footnote.

In addition to the regular quarterly publication of Issues of ERQ, comments or links to current developments may be posted to the website from time to time, particularly where timeliness is a consideration.

The ERQ invites readers to offer commentary on published articles and invites contributors to offer rebuttals where appropriate. Commentaries and rebuttals will be posted on the ERQ website (www.energyregulationquarterly.ca).

ENERGY REGULATION QUARTERLY

TABLE OF CONTENTS

EDITORIAL

Managing Co-Editors
Karen J. Taylor and Moin A. Yahya

THE PERIL AND PROMISE OF INTERESTING TIMES

Since publication of the last ERQ issue, there have been additional dramatic changes in the political and economic landscapes in the United States and around the world that are shaping events here at home in Canada. These are indeed "interesting" times but not without both peril and promise.

ACTIONS ABROAD

Recent tension in the Middle East has been escalating since the October 7, 2023, attack by Hamas on southern Israel, followed by the exchange of missiles by Israel and Iran in 2024, and the Twelve-day War in June 2025, in which the United States launched an air strike on Iranian nuclear sites[1]. On February 28, 2026, without consulting their allies or obtaining U.S. Congressional approval, the United States and Israel launched airstrikes on Iran. Without a clear rationale for initiating the war and a strategy for ending it, the potential for larger, drawn-out conflict remains on the table.

Of course, by the time this issue of ERQ is published there may be either a restoration of peace in the Middle East or an ongoing conflict that has escalated. If the latter, there is no shortage of potential geopolitical and economic consequences – including strong incentives for Iranian retribution and revenge, a global recession, agricultural crop production disruption, shortages of refined petroleum products (such as transportation and heating and power fuels and other products), a more aggressive transition to or from renewable energy resources and electric cars[2], and higher global market-based prices for energy, to name a few.

With this backdrop, the limitations of illiberal, far-right, authoritarian regimes came into full view with the ouster of Viktor Orbán as Prime Minister of Hungary. Orbán's 16-year reign came to an end on April 12, 2026[3] when voters handed the centre-right Tisza opposition party a parliamentary majority. The ouster of Orbán, long considered Russian President Vladimir Putin's closest European Union ally, means that Russia no longer has an ally that can thwart European Union assistance to Ukraine, which may signal a shift in the current power dynamic. Orbán was also a close ally of President Trump, who even dispatched his Vice President to rally support for Orbán in the closing days of the election.[4]

The war in Iran and Orbán's electoral defeat may prove to be minor setbacks for President Trump, but at home in the United States, the cumulative adverse effects of the President's policy agenda — chaos, lack of certainty and confidence, and higher prices — suggest

[1] UK, House of Commons Library, *Iran: Impacts of June 2025 Israel and US Strikes*, Research Briefing No CBP-10292 (London: House of Commons Library, 2025), online: <commonslibrary.parliament.uk/research-briefings/cbp-10292/>; See also Mariel Ferragamo, "U.S., Israel Attack Iranian Nuclear Targets—Assessing the Damage", *Council on Foreign Relations* (25 June 2025), online: <cfr.org/articles/us-israel-attack-iranian-nuclear-targets-assessing-damage>.

[2] Gabriel Friedman, "Electric Vehicles Could Rebound", *Financial Post* (14 April 2026), online: <financialpost.com/commodities/energy/electric-vehicles/electric-vehicles-could-rebound>.

[3] Ashifa Kassam & Flora Garamvolgyi, "Viktor Orbán Concedes Defeat as Opposition Wins Hungarian Election", *The Guardian* (12 April 2026), online: <theguardian.com/world/2026/apr/12/viktor-orban-concedes-defeat-as-opposition-wins-hungarian-election>.

[4] Paul Kirby, "JD Vance defends backing 'great guy' Orbán's campaign after landslide defeat", *BBC News* (14 April 2026), online: <bbc.com/news/articles/c8dll93j7d5o>.

that it is no longer on a steady path. Rising oil prices and the resulting negative impact on domestic inflation[5] may weaken support for the Republican party in the upcoming midterm elections.

On the judicial front, on February 20, 2026, the United States Supreme Court held that the International Emergency Economic Powers Act ("IEEPA") did not give the President the power to unilaterally impose tariffs on imports from any country anywhere in the world, at any rate, and for any duration the President chose.[6] The case was a complex one, brought by 7 small businesses and 12 states, filed in two separate actions in two different federal district (trial) courts. President Trump claimed emergency powers to deal with two foreign threats: 1) drugs from Mexico, China, and Canada, and 2) large and persistent trade deficits. The IEEPA gives Presidents the power to deal with significant foreign threats, and it was these two threats that led to the President announcing a comprehensive, global portfolio of tariffs on April 2, 2025, a day that has become known as 'Liberation Day'.

Ultimately the Court ruled in a 170-page, 6-3 decision that the President could not use the IEEPA to impose his sweeping tariffs. This decision is only the start, not the conclusion of the debate surrounding President Trump's signature economic policy, and as such, President Trump immediately imposed a 10% tariff on most imports, although many Canadian exports to the U.S. are exempt.[7]

Finally, the Canada-US-Mexico Agreement ("CUSMA") is scheduled to be reviewed in July 2026 giving parties the opportunity to negotiate modifications and vote on whether to renew the agreement for another 16 years. If CUSMA is not renewed, the present agreement will be subject to annual reviews until the expiry in 2036[8]. The July 2026 review is likely to occupy the Canadian federal government's efforts and energies over the balance of the year.

THE RESPONSE AT HOME

As of April 13, 2026, Prime Minister Carney now commands a majority government in the House of Commons, with 174 seats, as a result of defections of five members of parliament from two of the four federal opposition parties and victories by the Liberal Party of Canada in three by-elections.[9] It is the first time in Canadian history that a federal government has switched from a minority to a majority between elections[10] and is perhaps a manifest recognition that the fundamental challenges faced by Canada are rooted in its tumultuous relationship with the Trump administration in the United States. The next federal election in the United States is in November 2028 – the key implication being that domestic consequences arising from international actions are likely to dominate the Canadian political agenda until the next Canadian federal election, which must occur prior to October 15, 2029[11].

As a result, for the foreseeable future there will likely be more political stability in Ottawa and, potentially, a more active legislative agenda. An example of which was the April 14th announcement by the Prime Minister of the temporary suspension of the federal fuel excise tax on gasoline and diesel from April 20, 2026

[5] "United States Inflation Rate", *Trading Economics*, online: <tradingeconomics.com/united-states/inflation-cpi>.

[6] *Learning Resources Inc v Trump*, 607 US ___ (2026), online: <supremecourt.gov/opinions/25pdf/24-1287_4gcj.pdf>.

[7] "Trump imposes new 10% global tariff after U.S. Supreme Court loss, though Canada's largely exempt", CBC News (last modified 20 February 2026), online: <cbc.ca/news/world/livestory/scotus-tariff-ruling-9.7099048>.

[8] The Hub Staff, "Need to Know: What Happens if Canada and the U.S. Can't Come to an Agreement on CUSMA", *The Hub* (2 October 2025), online: <thehub.ca/2025/10/02/need-to-know-what-happens-if-canada-and-the-u-s-cant-come-to-an-agreement-on-cusma>.

[9] John Paul Tasker, "Carney clinches a majority government with 3 Liberal byelection wins", *CBC News* (last modified 14 April 2026), online: <cbc.ca/news/politics/byelection-liberal-conservatives-carney-majority-government-9.7161054>.

[10] Sarah Ritchie, "Carney Liberals to form historic majority after sweep of three byelections", *GuelphToday* (13 April 2026), online: <guelphtoday.com/local-news/breaking-carney-liberals-clinch-majority-with-wins-in-two-toronto-byelections-12138188>.

[11] *Canada Elections Act*, SC 2000, c 9, s 56.1(2). See also Elections Canada, "ElectoFacts", online:<elections.ca/electofacts>.

to September 7, 2026.[12] Provincial governments will now have to make some degree of peace with Prime Minister Carney being the Prime Minister and the Liberal Party of Canada possessing its first majority government since 2015. What this "peace" looks like and how durable it is, remains to be seen.

That said, there continue to be provincially led initiatives that challenge existing federal – provincial constitutional authorities and processes and yet others that advance cooperative federalism:

- On March 24, 2026, Alberta, Ontario, Quebec and Saskatchewan wrote a letter to Prime Minister Carney calling for constitutional change "for a new collaborative approach to judicial appointments".[13]

- Since our last issue of ERQ, Nova Scotia and Alberta have both signed impact assessment cooperation agreements under the federal *Impact Assessment Act* ("*IAA*"), streamlining the approval process for projects that would have required environmental assessments and approvals from both the federal and provincial governments.[14] The Alberta – Canada agreement sets out the circumstances where Canada will rely on Alberta's environmental assessment or regulatory processes to assess the effects of a project, including adverse effects within federal jurisdiction and reciprocal arrangements, with the integration of Alberta's environmental assessment and regulatory process requirements into the federal assessment, if applicable and desired by Alberta, as per the Agreement[15].

  Discussions with the Yukon, Saskatchewan, Quebec, and Newfoundland and Labrador continue; However, these provinces had several cooperation agreements with the Government of Canada under the *Canadian Environmental Assessment Act, 1992*.[16]

- On April 14, Alberta announced that it was introducing legislation, the *Expedited 120-Day Approvals Act* (Bill 30) to streamline approvals for major project investments, defined as projects that are aligned with provincial priorities, have minimum capital investment of $250 million, and are of strategic economic importance.[17] If passed, such projects would have a 120-day approval timeline. The legislation creates the process, application requirements, and criteria for approvals to guide project proponents and regulators alike. However, to be

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[12] Office of the Prime Minister of Canada, "Prime Minister Carney Suspends Federal Fuel Excise Tax on Gasoline and Diesel", news release (14 April 2026), online: <pm.gc.ca/en/news/news-releases/2026/04/14/prime-minister-carney-suspends-federal-fuel-excise-tax-gasoline-and>.

[13] Government of Alberta, "Motion for constitutional change in appointments: Alberta's government will introduce a motion calling for constitutional amendments that give the province a say in superior court appointments", news release (24 March 2026), online: <alberta.ca/release.cfm?xID=959368279B435-BF1E-97D7-D0501D47FD3F45F8>; Government of Alberta, "Provinces unite to reform judicial appointments: Alberta, Ontario, Quebec and Saskatchewan are calling on the federal government to reform judicial appointments and give provinces a formal, meaningful role", news release (24 March 2026), online: <alberta.ca/release.cfm?xID=958863EFF1512-ED54-0BE4-09355087618E7220>.

[14] Government of Alberta, "Final agreement signed for major project reviews

A finalized federal-provincial agreement will reduce duplication in major project reviews, strengthen investor certainty and rely more on Alberta's regulatory system", news release (2 April 2026), online: <alberta.ca/release.cfm?xID=9595512DD9E9A-AFC3-7066-E533D12DA0A6EB8A>.

[15] Impact Assessment Agency of Canada, "Canada–Alberta Cooperation Agreement", online: <canada.ca/en/impact-assessment-agency/corporate/acts-regulations/legislation-regulations/canada-alberta-cooperation-agreement.html>.

[16] Impact Assessment Agency of Canada, "Environmental Assessment Agreements", online: <canada.ca/en/impact-assessment-agency/corporate/acts-regulations/legislation-regulations/environmental-assessment-agreements.html>.

[17] Government of Alberta, "Faster approvals for major projects: Alberta's government is introducing legislation to approve priority projects critical to the province's economic future faster", news release (14 April 2026), online: <alberta.ca/release.cfm?xID=960007FC5FC39-E742-3256-178A5426A76D7C83>; Emily Williams, "Alberta government introduces 120-day approvals for major energy projects", *CBC News* (14 April 2026), online: <cbc.ca/news/canada/edmonton/alberta-government-120-day-approvals-major-energy-projects-9.7163707>.

considered for a qualified designation, project proponents will also be required to complete, or have substantially completed, the environmental impact assessment process and Indigenous consultation. The proposed legislation does not change Alberta's duty to consult.[18]

- On January 23, the Alberta Court of Appeal released its latest Reasons for Decision arising out of the fourth case management Advice and Directions meeting relating to the ongoing challenge of the federal *Clean Electricity Regulations*.[19]

- Prospect of referendums on independence in Quebec[20] and Alberta, notwithstanding the decision of Alberta Court of King's Bench on April 10, 2026, to prohibit the certification of petition results or make a referral to the Alberta Minister of Justice until the Court has ruled on the Applications by Athabasca Chipewyan First Nation and the Blackfoot Nations.[21]

If necessity is the mother of invention, then the March 3, 2026 report by legal scholars Paul Daly and Mark Mancini entitled "The Single Market Myth: How Ottawa and the provinces can finally dismantle Canada's costly internal trade barriers"[22] is a must read for those in the energy, regulation, and law space who are looking for potential cooperative arrangements that could meet the challenge of Canada's constitutional structure for the energy file. Herein lies the promise of "interesting times" - when Canada's aspiration to be an "energy superpower" hangs in the balance.

THIS EDITION

We begin this issue with a comment from Matthias Hofmann in response to the article by Ahmad Faruqui on real-time electricity pricing, published in ERQ Volume 13, Issue 3[23]. In the comment entitled: "Recent developments on real-time pricing in Norway", Matthias Hofmann, Master of Science and Senior Advisor at Statnett, provides empirical evidence on the potential and limitations of real-time pricing in practice in Norway, in the context of changing regulatory approaches to real-time pricing. Using the most recent data from Norway, Hofmann provides some insight into rate design, something that continues to challenge companies, consumers, and regulators alike in Canada.

Mohammed El Mendri, associate lawyer at PNL Advocacy and legal research counsel at the Canadian Gas Association, pens a "Report on the *ERQ* Energy Law Forum 2026" in which he provides a high-level summary of the Forum's proceedings on May 4 and 5, 2026 in Montreal. El Mendri concludes with the thought that energy law is now evolving at the pace of the country's political and economic news and invites readers to stay tuned for upcoming issues of *Energy Regulation Quarterly* for continued discussion of the issues raised at the *ERQ* Energy Law Forum.

In the article "The Proposed Co-operation Agreement on Environmental and Impact Assessment between Canada and Alberta", Nigel Bankes, Emeritus Professor of Law at the University of Calgary, analyzes the draft

[18] "Faster Approvals for Major Projects", *BOE Report* (15 April 2026), online: <boereport.com/2026/04/15/faster-approvals-for-major-projects>.

[19] *Reference re Clean Electricity Regulations (Canada)*, 2026 ABCA 22.

[20] Alex Cool-Fergus, "The Next Separatist Crisis Isn't in Alberta. It's in Quebec", *The Walrus* (4 February 2026), online: <thewalrus.ca/the-next-separatist-crisis-isnt-in-alberta-its-in-quebec>.

[21] *Athabasca Chipewyan First Nation v Alberta (Chief Electoral Officer)*, 2026 ABKB 278. Earlier, another judge had declared the referendum as having questionable constitutional validity, although the Government of Alberta amended its legislation to allow the collection of signatures to continue. See *Chief Electoral Officer of Alberta v Sylvestre*, 2025 ABKB 712.

[22] Paul Daly & Mark Mancini, *The Single Market Myth: How Ottawa and the Provinces Can Finally Dismantle Canada's Costly Internal Trade Barriers* (Ottawa: Macdonald-Laurier Institute, 3 March 2026), online: <macdonaldlaurier.ca/the-single-market-myth-how-ottawa-and-the-provinces-can-finally-dismantle-canadas-costly-internal-trade-barriers>.

[23] Ahmad Faruqui, "Real-Time Pricing of Electricity for Households: An International Survey" (2025) 13:3 Energy Regulation Q, online: <energyregulationquarterly.ca/articles/real-time-pricing-of-electricity-for-households-an-international-survey>.

co-operation agreement on "Environmental and Impact Assessment" between Canada and Alberta. Bankes discusses a background paper of the Impact Assessment Agency of Canada ("IAAC") that informs the various co-operation agreements already in place with other provinces, before critiquing the draft Canada/Alberta agreement. Bankes reviews the agreement in some detail before offering critical thoughts on what he sees as a federal abdication in the area of impact assessment.

Pierre-Olivier Pineau, Professor, Department of Decision Sciences at HEC Montréal, takes a detailed look at the energy industry in Quebec, in his article "The state of energy in Quebec". Pineau assesses the portfolio of energy used in the province by type and purpose, describes the organization of the energy sector, and analyzes the challenges facing Quebec's energy industry in the future.

In the article "Utility asset dispositions in an era of climate change: Who pays?", former Chair of the Alberta Utilities Commission ("AUC"), Mark Kolesar examines what happens when utility assets that are not yet fully depreciated are no longer considered used and useful for the purpose of setting just and reasonable rates. He highlights the two ways in which utility assets are adversely affected by climate change: premature destruction due to climate-related events and because of the policy or legislative requirements of government(s) to address climate change. The question of "who pays" is an enduring one, and Kolesar describes how these "stranded assets" have been treated across various North American jurisdictions.

Alberta has replaced the previous default rate for small retail consumers with a new default rate: the Rate of Last Resort ("RoLR"). As discussed by Chloe Haley, an economics student at the University of Calgary, in the article "The implications of price stability under the Rate of Last Resort regulation for low income consumers in Alberta", the design of the RoLR may produce a number of unintended consequences. Haley conducts empirical analysis on the Rate of Last Resort and provides some insights into its design and impact on consumption patterns.

In "Case Commentary: West Whitby Landowners Group Inc. v Elexicon Energy Inc.",[24] Reena Goyal, Energy Lawyer and Alice Xie, articling student, both of Blake, Cassels & Graydon LLP, and Roy Hrab, Senior Manager, Policy Research at Power Advisory LLC, discuss when an intervention of the Ontario Energy Board ("OEB") in a cost sharing dispute constitutes a reviewable decision. The authors focus their comments on the Court's analysis of the nature of the OEB letters and whether the OEB's intervention amounted to a statutory power of decision. The authors also discuss the role of delegated decision-making at the OEB and highlight the need for clarity on what types of OEB staff communications are binding versus non-binding.

Matthew Ghikas, Partner and Niall Rand, Associate, both of Fasken Martineau DuMoulin LLP, in their article "BC Utilities Commission Approves a significant investment in natural gas resiliency" discuss the October 27, 2025 Decision of the British Columbia Utilities Commission ("BCUC") to grant a Certificate of Public Convenience and Necessity ("CPCN") to FortisBC Energy Inc.'s Tilbury Liquefied Natural Gas Storage Expansion Project. The authors discuss the iterative regulatory process and evolved evidence needed to address the issue of natural gas system resiliency in the absence of industry wide resiliency standards in order to demonstrate need and that the project is in the public interest.

This issue concludes with an article by Adam White, founder and CEO of Powerconsumer Inc., "Caution before convergence: Reflections on the OEA's Ontario DSO Roadmap – *Institutional Roles, Regulatory Sequencing, and the Economics of DER Value*". In this comprehensive article, White describes the Ontario Energy Association's *Ontario DSO Roadmap* and assesses whether the early commitment to a specific DSO market form is warranted, before outlining a capability-first path forward that preserves regulatory optionality while allowing practical DSO progress to continue. ■

[24] *West Whitby Landowners Group Inc v Elexicon Energy Inc*, 2025 ONCA 821.

RECENT DEVELOPMENTS ON REAL-TIME PRICING IN NORWAY

Comment on Ahmad Faruqui, "Real Time Pricing of Electricity for Households: An International Survey"[1]

*Matthias Hofmann**

INTRODUCTION

In his international survey on real-time pricing for households, Faruqui highlights Norway as a prominent example, due to its exceptionally high share of households on electricity contracts tied to the hourly day-ahead spot price. Recent figures show that approximately 97 per cent of Norwegian households have real-time pricing retail contracts.[2] This widespread adoption makes Norway a particularly relevant case for assessing both the potential and the limitations of real-time pricing in practice. Thus, I aim to inform readers about recent developments in real-time pricing in Norway.

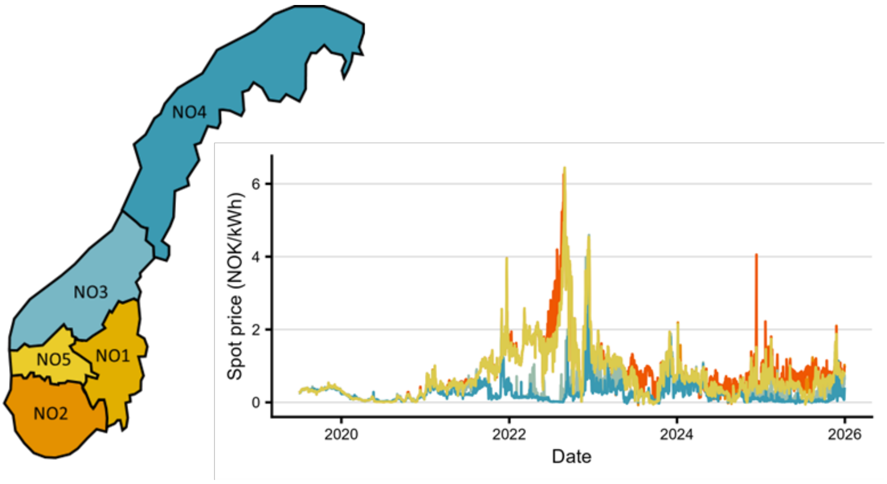
For many years, price-based demand response among Norwegian households was limited. Electricity prices were generally low and exhibited relatively little volatility, providing weak incentives for households to adjust consumption in response to hourly price signals. This situation changed abruptly in autumn 2021, when electricity prices increased sharply and volatility rose significantly, as illustrated in Figure 1. The main reason was a rapid increase in European natural gas prices, reflecting an increasingly tight gas market due to reduced Russian gas supplies already prior to the full-scale invasion of Ukraine in February 2022. As gas-fired power plants often set the marginal price in the electricity market, these developments led to higher wholesale electricity prices across Europe. Through integrated European electricity markets, this translated into higher and more volatile electricity prices in Norway, despite the fact that Norwegian electricity generation relies predominantly on hydro-power, complemented by wind power. As a result, electricity costs became highly visible for households, and price responsiveness became far more relevant.

[1] Ahmad Faruqui, "Real Time Pricing of Electricity for Households: An International Survey" (April 2025) 13:3 Energy Regulation Q, online: <energyregulationquarterly.ca/articles/real-time-pricing-of-electricity-for-households-an-international-survey>.

* Matthias Hofmann is a Senior Advisor at Statnett, the Norwegian transmission system operator, working on system utilisation and flexibility in power systems. Prior to this role, he held several positions at Statnett and SINTEF—one of Europe's largest independent research organisations—focusing on power system analysis and research program management. He holds a PhD from NTNU on demand-side flexibility as an alternative to grid investments, and a Master's degree in Industrial Engineering and Management from Technische Universität Ilmenau. His work focuses on electricity market design, demand flexibility, and security of supply, combining empirical analysis and applied research in the Norwegian and European power systems.

[2] Statistics Norway, *Breakdown of Electricity Sales: Electricity Prices in the End-User Market, by Type of Contract and Quarter*, table 14491 (16 February 2026), online: Statistics Norway <ssb.no/en/statbank/table/14491?sq=30120598>.

Figure 1: Map of the Norwegian bidding zones (zonal pricing areas) grouped into South Norway (NO1, NO2, NO5) and North Norway (NO3, NO4) with their respective spot prices July 2019 – December 2025.[3]



Empirical evidence indicates that while average households responded only weakly to hourly price variations, overall electricity consumption declined by approximately 11 to 14 per cent following the sharp increase in electricity prices from autumn 2021.[4] Another consequence was an increased adoption of smart technologies for controlling electricity consumption which increased households' ability to respond to hourly electricity prices. These technologies include smart electric vehicle charging, smart electric water boilers, and control of electric space heating, which is widespread in Norway. Among these, smart electric vehicles ("EV") charging plays an increasingly important role in price response.

BACKLASH AND WEAKENING OF PRICE SIGNALS

Despite the high prevalence of real-time pricing contracts, increased price levels and volatility have triggered a political and societal backlash against strong price exposure for households.[5] Importantly, this backlash has not primarily taken the form of households switching from real-time pricing contracts to fixed-price contracts, which remain available. Instead, the backlash has mainly taken the form of government-introduced electricity cost support schemes aimed at reducing household electricity costs, but with the side effect of substantially weakening or even removing the effective price signal faced by households.

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[3] This graphic was designed by the author of the present article using data collected from the following database: Nord Pool, "Day-ahead Prices" (last accessed 29 May 2026), online: Nord Pool <data.nordpoolgroup.com/auction/day-ahead/prices?deliveryDate=latest&currency=EUR&aggregation=DeliveryPeriod&deliveryAreas=AT>.

[4] Matthias Hofmann & Hanne Sæle, "A Comparative Analysis of Implicit Demand Side Response among Norwegian Electricity Consumers during the 2022/23 Energy Crisis", presented at CIGRE Paris Session 2024. *See also* Matthias Hofmann & Karen Byskov Lindberg, "Residential Demand Response and Dynamic Electricity Contracts with Hourly Prices: A Study of Norwegian Households during the 2021/22 Energy Crisis" (February 2024) 13 Smart Energy 100126, online: <doi.org/10.1016/j.segy.2023.100126>.

[5] Tone Sofie Aglen, "Strømspøkelset er tilbake", *NRK* (12 December 2024), online: <nrk.no/ytring/stromspokelset-er-tilbake-1.17166606> [in Norwegian].

Early support schemes were designed in a way that partially preserved incentives for price response. However, over time, the design of these schemes has increasingly weakened the link between spot prices and household electricity costs. This development culminated in October 2025 with the introduction of a fixed-price scheme, commonly referred to as the "Norway price", which effectively removes real-time price exposure for participating households.

EVOLUTION OF NORWEGIAN ELECTRICITY SUPPORT SCHEMES

Norwegian electricity support schemes[6] have evolved since their introduction at the end of 2021 in response to the sharp increase in electricity prices. Each subsequent design change has affected how households face spot-price signals, progressively weakening these incentives for changing their electricity consumption. It is important to bear in mind that these support schemes do not affect or replace retail electricity contracts, which for most households are based on real-time pricing.

- **Monthly electricity support scheme (introduced December 2021):**[7]

  Under the original monthly support scheme, the state compensated households a percentage of the electricity price exceeding a predefined threshold. While the parameters changed over time, the scheme ultimately covered 90 per cent of the price above the threshold of 0.70 NOK/kWh excluding VAT, with compensation paid via the grid tariff. The payout was calculated using the average monthly spot price and the household's actual electricity consumption for the month. Since the compensation was based on the monthly average price, households still faced the full hourly price variation within the month. Shifting consumption from expensive hours to cheaper hours therefore reduced the electricity bill without affecting the level of support, preserving incentives for load shifting.

- **Hourly electricity support scheme (introduced September 2023):**[8]

  Under the hourly electricity support scheme, compensation was based on the actual hourly spot price and the household's electricity consumption in the corresponding hour, rather than on monthly average values. The threshold price was gradually increased and reached 0.77 NOK/kWh excluding VAT from January 2026, while the compensation rate remained at 90 per cent. This scheme substantially reduced incentives for load shifting during hours when prices exceeded the threshold, as 90 per cent of the price difference was reimbursed. Although households still faced price variation below the threshold, the overall strength of the price signal from spot prices was significantly weakened, particularly during high-price periods when demand response would have been most valuable for the power system.

- **"Norway price" (introduced October 2025):**[9]

  The "Norway price" is a voluntary, opt-in support scheme. Households that do not opt in remain on the hourly electricity support scheme. The "Norway price" is a fixed electricity price set at

[6] Government of Norway, *Støtte til husholdninger — Innretning på strømstønadsordningen de siste årene*, online: Regjeringen <regjeringen.no/no/tema/energi/strom/regjeringens-stromtiltak/id2900232> [in Norwegian].

[7] Office of the Prime Minister, Ministry of Energy & Ministry of Finance (Norway), "Government Launches Electricity Support Package Worth Billions" (11 December 2021), online: Regjeringen <regjeringen.no/en/whats-new/government-launches-electricity-support-package-worth-billions/id2891839>.

[8] Ministry of Energy (Norway), "Mer treffsikker strømstønadsordning til husholdningene" (11 May 2023), online: Regjeringen <regjeringen.no/no/aktuelt/mer-treffsikker-stromstonadsordning-til-husholdningene/id2976901> [in Norwegian].

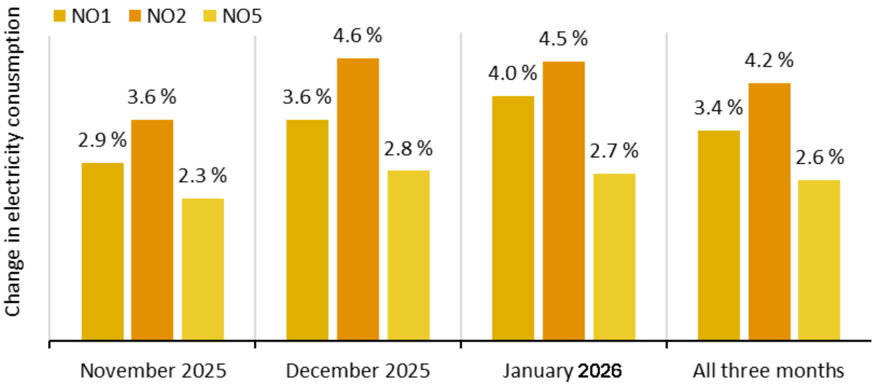
[9] Ministry of Energy (Norway), "Norway Price to Ensure Predictable and Stable Electricity Prices for Consumers" (17 March 2025), online: Regjeringen <regjeringen.no/en/whats-new/norgespris-skal-sikre-forutsigbare-og-stabile-strompriser-for-folk/id3090849>.

0.40 NOK/kWh excluding VAT. Households receive compensation via the grid tariff when the spot price exceeds the fixed price and have to pay the difference when it falls below this level. Once opted in, a household remains on the scheme until the end of the calendar year, although opt-in into the scheme can occur at any point during the year. In Southern Norway, where expected average spot prices for 2026 are significantly higher than 0.40 NOK/kWh, the scheme is highly attractive. As of April 2026, approximately two-thirds of households in the southern bidding zones had opted into the Norway price.[10] By design, the scheme effectively removes all short-term price signals for households with "Norway price".

FIRST EVIDENCE ON THE EFFECTS OF THE "NORWAY PRICE" ON THE ELECTRICITY CONSUMPTION

Early, not-yet-published empirical analyses[11] indicate two main effects of the "Norway price". First, household with "Norway price" increase their electricity consumption by a few per cent compared with households that remain on the hourly electricity support scheme within the same bidding zone, as shown in Figure 2. This can be explained by the lower electricity price and the resulting weaker incentive to conserve electricity. Second, the increase in consumption appears to follow the typical household load profile, with relatively larger percentage increases in the afternoon and evening hours, as seen in Figure 3. This implies that electricity consumption increases particularly during peak load hours. One plausible explanation is that households on the fixed-price scheme reduce load shifting to nighttime hours with lower spot prices. As a result, the removal of real-time price signals not only increases total consumption but may also exacerbate peak demand at system level.

Figure 2: Change in household electricity consumption during the winter months among households enrolled in the "Norway price" scheme, after the scheme was introduced[12]

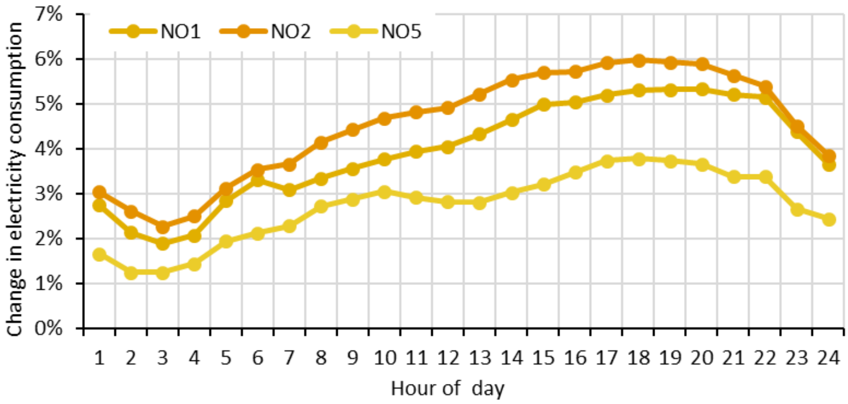


[10] Elhub, *Statistikk for Norgespris*, online: Elhub <elhub.no/data-og-innsikt/statistikk-for-norgespris> [in Norwegian].

[11] Kristine Johanne Viddal Moen, Synne Lefdal, Matthias Hofmann & Karen Byskov Lindberg, "Lower Electricity Prices, Higher Demand? — The Effect of Introducing a Subsidized Flat Electricity Price to Norwegian Households" (paper accepted at the 22nd International Conference on European Energy Market (EEM 2026), Trondheim, Norway, 22–24 June 2026) [unpublished].

[12] *Ibid*.

Figure 3: Change in household electricity consumption by hour of day in January 2026 among households enrolled in the "Norway price" scheme[13]



CONCLUSION

Norway provides an interesting case for assessing real-time pricing for households, combining near complete exposure to hourly spot prices with policy interventions during periods of high and volatile electricity prices. The experience since autumn 2021 shows that strong price signals can matter: although average households responded only weakly to short-term hourly price variation, high prices led to a substantial reduction in aggregate electricity consumption and accelerated the adoption of smart technologies to control electricity consumption. At the same time, the subsequent introduction of various electricity support schemes has progressively weakened household exposure to real-time price signals. Emerging evidence suggests that this removal of price incentives increases electricity consumption and may increase peak demand at system level by reducing load shifting.

In summary, the Norwegian case underscores that the effectiveness of real-time pricing for households depends not only on retail contract design and technology, but also on the surrounding policies aimed at lowering electricity costs for households and their effects on household price exposure. ■

[13] *Ibid*.

REPORT ON THE ERQ ENERGY LAW FORUM 2026

*Mohammed El Mendri**

DAY 1

Opening Remarks and Presentation of the Kaiser Energy Bison Award

On May 4 and 5, 2026, *Energy Regulation Quarterly* hosted the annual Energy Law Forum ("ELF") meeting in Montreal. The Forum opened with the presentation of the annual prize, the *Kaiser Energy Bison Award* 2026. This year, the award went to Timothy Egan, a lawyer by profession and a leading figure in energy governance, and until very recently, the President and CEO of the Canadian Gas Association ("CGA"), a position he held for more than ten years.

In his acceptance speech, Tim looked back on the genesis of the *Energy Regulation Quarterly* ("ERQ"). The need, he explained, was clear: a forum was required where regulatory decisions could be examined, criticized and debated. That need was the founding idea behind the journal, and thus the ERQ was born, the product of a partnership between the CGA and Electricity Canada ("EC"). However, one major question remained: how to establish the journal's credibility from the outset? The answer took the form of a prestigious co-editorship, already well known in energy and regulatory circles with two highly respected former regulators, the late Gordon Edward Kaiser and Rowland Harrison. Tim did not fail to recount the story behind the award's name. Before the pandemic, it was traditionally called the "Energy Bear". However, Gordon's passing provided an opportunity to pay tribute to the builder he was: no longer a bear, but a bison "in his honour, as he was".

The next speaker was Canadian pollster and data scientist Nik Nanos of Nanos Research. Nanos painted a portrait of Canadian public opinion on energy and of the country's political climate, which he organized around two main themes: energy rethought and the advancement of major projects, followed by the economic and political mood. Nanos presented various polls showing the current and changing mood of Canadians with respect to various issues facing the public. Overall, he concluded that while Canadians remain anxious about their bills, they are currently nonetheless giving the government the benefit of the doubt.

DAY 2

Panel 1: Administrative Law in 2025: The Year in Review

Professor Paul Daly, of the University of Ottawa, delivered his now eagerly awaited overview of the past year's developments in administrative law, an exercise he also publishes annually, in a more extensive form, in the *ERQ*.[1] The main theme of his review is the continuing expansion of the "*Vavilov* domain" (as he likes to call it) and of its culture of justification, according to which the legitimacy of a public decision rests on the reasons that support it, and not on the mere assertion of a power through its exercise. As such, Professor Daly reviewed the cases that address the question of

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[1] *See* Paul Daly, "2025 Developments in Administrative Law Relevant to Energy Law and Regulation" (2026) 14:1 Energy Regulation Q.

"how far must a regulator go in giving reasons for its decisions?" Another area Professor Daly canvassed was the court's treatment of statutory interpretation by regulatory agencies, especially with what he called the "open texture" of language where words in a statute can never anticipate in advance all the situations to which one might want to apply them. Related to this question is the role of precedents as a constraint on a decision-maker, something Professor Daly elaborated on with an example from a recent Supreme Court judgment.

Another area that continues to occupy regulatory lawyers' minds is the overlap between appeals and judicial review. Similarly, the issues of procedural fairness, bias, and the independence of decision-makers occupied a good amount of time in Professor Daly's review of the caselaw. Daly closed by flagging a few upcoming cases to follow closely. These cases will address fundamental questions such as: (1) whether a government, by statute, can prevent the courts from reviewing an administrative decision?; (2) how should a court review a decision that rests mainly on facts?; (3) when can a Quebec court review an administrative decision and with what degree of deference?; and (4) when an administrative decision engages a value protected by the *Charter*, such as freedom of expression, how rigorously must the courts verify that this value has indeed been respected?

Panel 2: The Consumer's Perspective on Canada's Energy Moment

Pollster Greg Lyle, founder and president of Innovative Research Group, presented his findings about consumer sentiments in Canada, especially with respect to energy issues. Mr. Lyle addressed several issues such as energy affordability and the cost of living. Using Atlantic Canada as an instructive example, Mr. Lyle discussed the role of process, social license, energy security, renewable energy, data centres, and public anxiety over world politics in shaping future energy policies.

Panel 3: Energy Law Issues Facing Regulators, from the Hearing to the Enforcement of Decisions

Mr. Lyle's discussion fed into the next panel which brought together Scott MacKenzie, KC, Professor Mark Mancini and David Morton. The theme was the independence of energy regulators, that quality so readily invoked, but which is measured above all in practice, in the hearing room, and once the decision has been rendered. David Morton, former Chair of the B.C. Utilities Commission, gave his perspective on regulatory independence from an international, comparative angle. A credible regulator, he recalled, rests everywhere on the same conditions: stable funding, transparency, accountability and is, above all, largely free from any political interference, something that remains to this day the foundation of a regulator's legitimacy. Scott MacKenzie, KC, the former Chair of Prince Edward Island's Island Regulatory and Appeals Commission ("IRAC"), also addressed the question from a Canadian perspective. He noted how various changes to the governance structure of regulatory agencies, such as shorter terms for decision makers, as well as external political pressures can sometimes challenge regulatory independence.

Professor of law, Mark Mancini addressed how judicial review allows courts to verify the legality of administrative decisions. The upcoming Supreme Court case of *Democracy Watch*[2] should provide an answer to the question of: can the legislature close off judicial review of questions of law to the courts and, if so, how far?

Panel 4: Regulatory Decision-Making in the Face of New Challenges

The next panel brought together Doug Slater, vice president of Indigenous relations and regulatory affairs at FortisBC and John Vellone, national lead partner of the Energy, Resources and Renewables group at the law firm BLG. The panel addressed two themes that regulators are grappling with today: (1) resilience, which has become a new challenge at the heart of regulators' mandate; and (2) innovation. Mr. Slater used the 2018 rupture of a major British Columbia gas pipeline to explain why resilience

[2] *Democracy Watch v Canada (Attorney General)*, 2024 FCA 158, leave to appeal to SCC granted, 41576 (16 May 2025).

is now central to utility planning and discussed the regulatory process, analysis, and planning framework needed to support investments to address energy system resiliency.

John Vellone discussed the question of how innovation and regulation can intersect and overlap, especially since modern regulators' mandates have been broadened to include an objective to facilitate innovation. Mr. Vellone discussed initiatives such as regulatory sandboxes, host pilot projects, and small-scale trials that allow the feasibility, timelines, costs, and risks of innovations to be tested.

Panel 5: The review of major projects

The final panel brought together Professor of Law Gerard Kennedy, Mark Watton, Lead Commissioner at the Canada Energy Regulator, and Terence Hubbard, President of the Impact Assessment Agency of Canada. The discussion focused on how major projects are approved in Canada and on the federal government's recent desire to speed up their delivery, in particular through the new *Building Canada Act*[3] and designations of projects in the national interest.

Professor Kennedy laid the groundwork: the federal government may make laws for "the peace, order and good government of Canada"[4]. Yet, to prevent the federal government from being able to regulate everything, case law has framed this power, the most important strand of which is the "national concern" doctrine.[5] Kennedy emphasized that "national interest" is not a constitutionally defined term, is context-dependent and cannot be used simply to bypass provincial authority. Even if the *Act* is valid generally, each project designation must itself fall within federal jurisdiction and respect constitutional limits, including Indigenous rights.

Mark Watton explained how the Canada Energy Regulator (CER) works today and how the new Act[6] could change things. The projects the CER deals with most are oil and gas pipelines, have always been a politically sensitive subject as they touch many interests. Today, a proponent files an application, and depending on the size of the project, the Regulator may send cabinet a report recommending the project, or not, in the public interest, supported by conditions. The Act[7] lists the factors to be considered, including economic viability, effects on Indigenous peoples, environmental issues, the proponent's capacity, and social and economic factors.

Terence Hubbard, for his part, addressed how his agency revised its framework in the spring of 2024 and tightened its decision-making. Whereas only one cooperation agreement had been concluded in ten years, it now has seven with the provinces, with another one nearly finalized with Newfoundland and Labrador, and discussions under way with Saskatchewan and Quebec. The agency can also rely on the new Major Projects Office that can designate projects in the national interest and coordinate regulatory work, while staying within federal jurisdiction and without encroaching on provincial decisions. Mr. Hubbard did stress, however, that given that Indigenous consultation is provided for by statute[8] and flows from the Constitution[9], no framework can dispense with it.

CONCLUSION

If one lesson emerges from these two days, it is that energy law now evolves at the pace of the country's political and economic news. The questions raised by the speakers, far from being settled, will only grow in importance between now and the next edition of the Energy Law Forum, where we hope to see readers and practitioners in great numbers. In the meantime, it is in the pages of the *ERQ* that these stories will continue to be written, and the ELF invites you to stay tuned for upcoming issues of *Energy Regulation Quarterly*. ■

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[3] *Building Canada Act*, SC 2025, c 2.

[4] *Constitution Act, 1867* (UK), 30 & 31 Vict, c 3, s 91, reprinted in RSC 1985, App II, No 5.

[5] *See References re Greenhouse Gas Pollution Pricing Act*, 2021 SCC 11. *See also R v Crown Zellerbach Canada Ltd,* [1988] 1 SCR 401 [*Crown Zellerbach*].

[6] *Ibid* [*Crown Zellerbach*].

[7] *Ibid.*

[8] *Ibid.*

[9] *Constitution Act, 1982*, s 35, being Schedule B to the *Canada Act 1982* (UK), 1982, c 11. *See Haida Nation v British Columbia (Minister of Forests)*, 2004 SCC 73, [2004] 3 SCR 511.

THE PROPOSED CO-OPERATION AGREEMENT ON ENVIRONMENTAL AND IMPACT ASSESSMENT BETWEEN CANADA AND ALBERTA[1]

*Nigel Bankes**

On March 6, 2026, the Governments of Canada and Alberta released a draft co-operation agreement on "Environmental and Impact Assessment", thereby leading the way to fulfilling one of the undertakings contained in the Memorandum of Understanding on Energy[2] ("MOU") signed by the two governments on November 27, 2025. The MOU committed the parties to "Negotiate a cooperation agreement on impact assessments on or before April 1, 2026, that reduces duplication through a single assessment process that respects federal and provincial jurisdictions." The Draft Agreement was open for comment until March 26, 2026.

While the MOU might have anticipated this particular proposed agreement, there is nothing new about this type of agreement. At one time such agreements were a routine part of intergovernmental relations in the environmental sphere. The website of the Impact Assessment Agency of Canada (IAAC or Agency) contains an historical listing[3] of such agreements under successive federal environmental impact assessment statutes. For example, Canada and Alberta negotiated

[1] This article was previously published in a different format as Nigel Bankes, "The Proposed Co-operation Agreement on Environmental and Impact Assessment between Canada and Alberta" (18 March 2026), online (blog): <ablawg.ca/2026/03/18/the-proposed-co-operation-agreement-on-environmental-and-impact-assessment-between-canada-and-alberta>. It is a comment on the Draft Co-operation Agreement on Environmental and Impact Assessment between Canada and Alberta, March 6, 2026. Government of Canada, "Draft Co-operation Agreement on Environmental and Impact Assessment Between Alberta and Canada" (6 March 2026), online (pdf): <letstalkimpactassessment.ca/51439/widgets/217426/documents/165367>.

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[2] Prime Minister of Canada, "Canada-Alberta Memorandum of Understanding" Calgary, Alberta (27 November 2025), online: <pm.gc.ca/en/news/backgrounders/2025/11/27/canada-alberta-memorandum-understanding>.

[3] Government of Canada, "Legislation and Regulations: Agreements related to assessments" (last modified 6 July 2016), online: <canada.ca/en/impact-assessment-agency/corporate/acts-regulations/legislation-regulations/environmental-assessment-agreements.html>.

the Agreement on Environmental Assessment Cooperation[4] in 2005 under the terms of the *Canadian Environmental Assessment Act*[5], but there was no such agreement between the two governments under the terms of *Canadian Environmental Assessment Act*[6].

Canada has also been actively negotiating another generation of cooperation agreements with other provinces at least loosely under the auspices of the current *Impact Assessment Act*[7]. One of these agreements (with British Columbia) predates the Reference re Impact Assessment Act[8], and the subsequent amendments to the *IAA*[9] but Canada has also negotiated a raft of agreements with other provinces in the last four months with Ontario[10], Nova Scotia[11], New Brunswick[12], Manitoba[13] and Prince Edward Island[14]. As an aside, the Agency's collation of these agreements also includes hyperlinks to the comments received on each agreement during the 21-day consultation period — useful resources for those thinking of submitting comments on the Alberta/Canada draft. Similarly, the Agency's site also provides a link to a background paper "'One' project, one review, Co-operation Agreements for the Assessment of Major Projects"[15], ("Background Paper") along with links to the many comments received on that paper. That paper, discussed below, informs the content of the current raft of agreements. Finally, the political impetus for these more recent agreements can be traced to the May 2025, Speech from the Throne[16] in which the federal government committed to reach cooperation agreements with every interested province and territory to realize the goal of "one project, one review"[17]. That speech also contained this commitment: "As Canada moves forward with nation-building projects, the Government will always be firmly guided by the principle of free, prior, and informed consent."[18]

THE BACKGROUND PAPER

The Background Paper identified three principal means for achieving the goal of "one project, one review": (1) early assessment decisions, (2)

[4] Government of Canada, "Canada-Alberta Agreement on Environmental Assessment Cooperation (2005)" (last modified 24 May 2019), online: <canada.ca/en/impact-assessment-agency/corporate/acts-regulations/legislation-regulations/canada-alberta-agreement-environmental-assessment-cooperation-2005.html>.

[5] *Canadian Environmental Assessment Act*, SC 1992, c 37.

[6] *Canadian Environmental Assessment Act,* 2012, SC 2012, c 19, s 52.

[7] *Impact Assessment Act*, SC 2019, c 28, s 1 [*IAA*].

[8] *Reference re Impact Assessment Act*, 2023 SCC 23.

[9] *Ibid*. For comment on those amendments see David V. Wright, "Constitutional Caution, Correction, and Abdication: The Proposed Amendments to the *Impact Assessment Act*" (10 May 2024), online (blog): <ablawg.ca/2024/05/10/constitutional-caution-correction-and-abdication-the-proposed-amendments-to-the-impact-assessment-act> [*Constitutional Caution*].

[10] Government of Canada, "Draft Co-operation Agreement between Ontario and Canada on Environmental and Impact Assessment" (last visited 9 April 2026), online: <letstalkimpactassessment.ca/co-operation-agreement-between-ontario-and-canada/news_feed/read-draft-co-operation-agreement-between-ontario-and-canada>.

[11] Government of Canada, "Co-operation Agreement between Nova Scotia and Canada" (last modified 16 February 2026), online: <letstalkimpactassessment.ca/co-operation-agreement-between-nova-scotia-and-canada>.

[12] Government of Canada, "Co-operation Agreement between New Brunswick and Canada" (last modified 16 February 2026), online: <letstalkimpactassessment.ca/cooperation-agreement-between-new-brunswick-and-canada?tool=news_feed#tool_tab>.

[13] Government of Canada, "Co-operation Agreement between Manitoba and Canada" (last modified 16 February 2026), online: <letstalkimpactassessment.ca/co-operation-agreement-between-manitoba-and-canada>.

[14] Government of Canada, "Draft Co-operation Agreement between Prince Edward Island and Canada on Environmental and Impact Assessment" (last modified 16 February 2026), online: <letstalkimpactassessment.ca/co-operation-agreement-between-prince-edward-island-and-canada/news_feed/draft-co-operation-agreement-between-prince-edward-island-and-canada>.

[15] Government of Canada, "'One Project, One Review': Co-operation Agreements for the Assessment of Major Projects" (last modified 16 February 2026), online: <letstalkimpactassessment.ca/one-project-one-review-cooperation-agreements-assessment-major-projects>.

[16] Canada, Parliament, Throne Speech, "Building Canada Strong: A Bold, Ambitious Plan for Our Future", 45th Parl, 1st Sess (27 May 2025), online (pdf): <canada.ca/content/dam/pco-bcp/documents/pm/STF2025_EN_Web.pdf>.

[17] *Ibid* at 12.

[18] *Ibid* at 17.

substitution of a provincial assessment for the *IAA* assessment (hereafter "substitution"), and (3) substitution to a harmonized process.

Early assessment decisions

The reference to early assessment decisions refers to the decision that the Agency must make under s 16(1) of the *IAA* once the proponent of a designated project has provided an initial project description ("IPD") and there has been an opportunity for public comment. "Designated projects" are listed and defined in the *Physical Activities Regulations*[19], including, for example "The construction, operation, decommissioning and abandonment of…a new coal mine with a coal production capacity of 5 000 t/day or more"[20]. This would include, for example, the latest iteration of the Grassy Mountain Coal[21] project of Northback Holdings.

The information that a proponent of a designated project must provide as part of an IPD is prescribed in Schedule 1 of the *Information and Management of Time Limits Regulations*[22]. Part E of that Schedule requires the proponent to provide information about the potential effects of the project on areas within federal jurisdiction including fish and fish habitat, aquatic species listed under the *Species at Risk Act*[23], migratory birds, interprovincial waters, greenhouse gas emissions and potential impacts on Indigenous peoples.

Based on the information in the IPD, the Agency must decide whether an impact assessment of the designated project is required in light of the factors listed in s 16(2) of the *IAA*. Of those factors, the Background Paper draws attention to one particular factor, namely item (f.1), added in the 2024 amendments to the Act, to the effect that the Agency should consider:

> …whether a means other than an impact assessment exists that would permit a jurisdiction to address the adverse effects within federal jurisdiction — and the direct or incidental adverse effects — that may be caused by the carrying out of the designated project.[24]

The Background Paper commentary suggests that a cooperation agreement might be a way in which the parties could commit

> …to share information early <u>regarding how provincial means could address federal effects</u> and, in appropriate cases, provide for continued IAAC support to the province to:
>
> - ensure adverse effects within federal jurisdiction are addressed in the provincial process, including through use of federal expertise;
> - incorporate the perspectives and Indigenous Knowledge of potentially impacted groups;
> - carry out Crown consultation obligations;
> - integrate permitting considerations into the assessment process to the extent possible to reduce federal permitting timelines; and/or
> - <u>develop legally binding conditions related to the adverse effects within federal jurisdiction</u>.[25]

I will refer to this as the "early assessment plus federal protection option". The premise here

[19] *Physical Activities Regulations*, SOR/2019-285.

[20] *Ibid*, s 18.

[21] Government of Alberta, Environment and Protected Areas, *Environmental Assessment – Northback Holdings Corporation Grassy Mountain Coal Mine Project* (Edmonton: Government of Alberta, 2022), online: <open.alberta.ca/publications/environmental-assessment-northback-grassy-mountain-coal-mine>.

[22] *Information and Management of Time Limits Regulations*, SOR/2019-283.

[23] *Species at Risk Act*, SC 2002, c 29.

[24] *Supra* note 7, s 16(2)(f.1).

[25] *Supra* note 14 at 4 [emphasis added].

is that the Agency may decide that a federal assessment is not required, even though the Agency has identified that the project may cause "adverse effects within federal jurisdiction". We will see that this option is reflected in s 1(1) in the Alberta Agreement and in all of the co-operation agreements negotiated to date.

A decision not to require an impact assessment for a designated project takes the project out of the *Impact Assessment Act* which can thus have no further application to the project. In plain terms, it is an early off-ramp from the federal process for a designated project. This makes it difficult to understand how the federal government will be able to use factor (f.1), even if supported by a cooperation agreement, to develop legally binding conditions to address the federal concerns referenced in the Background Paper. Federal leverage is lost once there is a determination that an impact assessment under the *IAA* is not required.

The second means for achieving the goal of "one project, one review" is substitution. Sections 31–33 of the *IAA* deal with the concept of substitution. The premise for substitution is that the Agency has decided that a designated project should be subject to an impact assessment under the *IAA*. These sections contemplate that the federal Minister may, on the request of a jurisdiction (here a province), agree to substitute a provincial process for the impact assessment that would otherwise be carried out under the *IAA*. The request must be posted for public comment, and the Minister may only agree to substitution if satisfied that a number of important conditions precedent will be met (s 33). The Background Paper summarizes these conditions as follows:

> For the Minister to approve such a request, the provincial process must address conditions set out in the IAA, including addressing the factors that would be addressed in a federal impact assessment, consulting with potentially affected Indigenous groups, providing an opportunity for the public to participate meaningfully in the assessment and involving federal experts throughout the assessment process. When an assessment is substituted, the federal government would continue to have a decision-making role following the assessment, in setting conditions to address significant adverse federal effects identified through the assessment, including, where appropriate, potential accommodations.[26]

The Background Paper notes that substitution has been used relatively frequently in British Columbia. In my view the *IAA* sets clear legal parameters for substitution unlike the "early assessment plus federal protection" referenced in the last section.

The third means for achieving the goal of "one project, one review", substitution to a harmonized process, is evidently a variant on simple substitution. It involves the joint design of a process to meet the needs of both federal and provincial impact assessment rules, and perhaps also those of Indigenous governments. The harmonized approach is expressly permitted by s 31(1)(b) of the *IAA* which contemplates a project specific agreement or arrangement under s 114 of the Act. Any agreement to adopt such an approach would also require the Minister to satisfy themself that the agreed approach will meet the same preconditions as for simple substitution. Accordingly, I am of the view that the *IAA* once again sets clear legal parameters for "substitution to a harmonized process".

Finally, the Background Paper references possible additional content for a co-operation agreement including joint review panels ("JRP"), such as that put in place by Alberta and Canada for the original Grassy Mountain project[27]. However, while some co-operation agreements reference JRPs (e.g. New Brunswick, Manitoba, Nova Scotia and Prince Edward Island) there is no reference to a JRP in either the Ontario or the Alberta agreements.

The next section of this comment provides an outline of the Canada/Alberta Agreement as well as some comparisons between this

[26] *Ibid* at 5.

[27] Joint Review Panel Established by the Federal Minister of Environment and Climate Change and the Alberta Energy Regulator, Benga Mining Limited, *Grassy Mountain Coal Project*, 2021 ABAER 010, Report of the Joint Review Panel, Crowsnest Pass (17 June 2021).

Agreement and some of the other provincial agreements. The concluding section assesses the legal significance of the Canada/Alberta Agreement.

THE DRAFT CANADA/ALBERTA AGREEMENT

The Agreement comprises a preamble (11 paragraphs) and 12 operative sections. Unlike earlier generations of impact assessment cooperation agreements, there is no definition section in any of these agreements.

The Preamble

The Preamble begins by referring to the Energy Memorandum of Agreement (although the Agreement is not confined to energy projects) and then offers a statement of the exclusive legislative powers of the province largely tracking language found in ss 92 and 92A of the *Constitution Act, 1867*. There are similar preambular statements in the other cooperation agreements, although the Alberta version, perhaps not surprisingly, emphasises the word "exclusive".[28] The Alberta agreement also offers a more expansive statement of provincial powers than the other agreements. Conspicuously absent from all of these agreements is a statement of the legislative jurisdiction of the federal government. Hence, although the agreements all recognize a shared responsibility for the environment, none of them articulate the bases for federal jurisdiction. The preambles of these agreements are therefore somewhat one-sided.

In common with all the other agreements, the preamble to the Alberta agreement contains several references to the rights of Indigenous peoples, including references to the duty to consult and accommodate and the goal of reconciliation. Most telling however is the manner in which the Agreement deals with the United Nations Declaration on the Rights of Indigenous Peoples ("UNDRIP"). Whereas the Preamble states that Canada maintains its commitment to UNDRIP, Alberta insists that it "continues to act in a manner that is consistent with treaties, the Canadian Constitution, and Alberta law, and views UNDRIP as non-binding". It is hard for me to accept that this self-serving statement belongs in the Preamble. In particular, Alberta's views as to the legal status of the Declaration are demonstrably wrong, at least with respect to those (many) elements of the Declaration that represent customary international law: *Nevsun Resources Ltd. v Araya*.[29]

Alberta's position is certainly unique in the context of the other agreements. Manitoba and Canada <u>share</u> the commitment "to ensuring that processes are informed by, and aligned with the principles" of UNDRIP while the provincial parties to the Ontario, New Brunswick and PEI agreements take no position on UNDRIP. Nova Scotia is more nuanced and less self-serving than Alberta:

> Nova Scotia advances Indigenous-Crown relations in accordance with existing Aboriginal law and Section 35 of the *Constitution Act, 1982* and has made no legislative commitment to implement UNDRIP and does not apply it as law.[30]

The preamble also contains the assertion that:

> Canada and Alberta have each established robust processes for the high-quality assessment of the effects of certain types of projects, informed by rigorous science, Indigenous consultation, public participation, and community knowledge;[31]

Many would contest elements of this assertion as it applies to Alberta's project review process, and in particular the way Alberta's process privileges participation by a narrow category of persons considered to be "directly affected",

[28] For commentary on the meaning of "exclusive" in the context of the division of legislative powers see Nigel Bankes & Andrew Leach, "The Word 'Exclusive' Does Not Confer a Constitutional Monopoly, Nor a Right to Develop Provincial Resource Projects", *ABlawg* (1 November 2023), online: ABlawg <ablawg.ca/2023/11/01/the-word-exclusive-does-not-confer-a-constitutional-monopoly-nor-a-right-to-develop-provincial-resource-projects>.

[29] *Nevsun Resources Ltd v Araya*, 2020 SCC 5.

[30] Government of Canada, *Co-operation Agreement between Nova Scotia and Canada on Environmental and Impact Assessment* (27 March 2026), online: Government of Canada <canada.ca/en/impact-assessment-agency/corporate/acts-regulations/legislation-regulations/canada-ns-cooperation-agreement.html>.

[31] *Supra* note 1 at 1.

thereby excluding many elements of civil society.[32] First Nations have also critiqued the adequacy of Alberta's impact assessment and regulatory processes.[33] Furthermore, the recent decision in the Rosebud Racetrack case[34] confirms that provincial decision-makers are very reluctant to concede the relevance and significance of federal listing decisions under the *Species at Risk Act*,[35] when it comes to discharging their responsibilities under provincial environmental legislation.

Substantive Provisions

The following are the headings for the substantive sections of the Alberta and Ontario Agreements. My selection of the Ontario Agreement for comparison purposes is somewhat arbitrary. While the agreements share many commonalities, the headings also suggest some differences, which I explore in the next sections.

Ontario	**Alberta**
1. One Project, One Assessment, & One Decision: Reliance on Ontario's Processes & Reciprocity	1. Reliance on Alberta's Processes and Reciprocity
2. Early Notification and Information Sharing	2. Early Notification and Information Sharing
3. Decision-making about the conduct of a federal impact assessment	3. Decision-making about the conduct of a federal impact assessment
4. Substitution to Ontario's process or a harmonized process	4. Co-operative assessments
5. Co-ordination of Potential Assessment conditions & decision-making and permitting	5. Timeline for completion of impact assessment
6. Indigenous peoples	6. Co-ordination of Potential Assessment conditions & decision-making and permitting
7. Information sharing & communications	7. Indigenous peoples
8. Resources	8. Information sharing & communications
9. Participant funding	9. Participant funding
10. Application of this agreement	10. Application of this agreement
11. General provisions	11. Issues management
12. Review	12. General provisions

[32] See, for example, the decision of the chief executive officer of the Alberta Energy Regulator to cancel a public hearing on a significant coal mine expansion project as discussed by Nigel Bankes & Shaun Fluker, "CEO of the Alberta Energy Regulator Denies Public Hearing Rights on a Coal Application", *ABlawg* (15 September 2025), online: ABlawg <ablawg.ca/2025/09/15/ceo-of-the-alberta-energy-regulator-denies-public-hearing-rights-on-a-coal-application>.

[33] See for example the request in 2024 by a number of Nations for the designation of the Pathways CO_2 Transportation Network and Storage Hub Foundational Project, Letter from Tribal Chiefs Ventures Pathways Working Group to the Honourable Steven Guilbeault, Minister of Environment and Climate Change (28 November 2024), requesting designation under the *Impact Assessment Act* of Pathways Alliance's Pathways CO_2 Transportation Network and Storage Hub Foundational Project in Alberta, online (pdf): <iaac-aeic.gc.ca/050/documents/p89090/159929E.pdf>, esp at 13 – 20. And for commentary see Nicole Achtymichuk & Shaun Fluker, "AER Declines Request for an Environmental Impact Assessment of the Pathways Project", *ABlawg* (23 December 2024), online (pdf): ABlawg <ablawg.ca/wp-content/uploads/2024/12/Blog_NASF_Pathways_Project.pdf>.

[34] *Skibsted v Alberta (Environment and Protected Areas)*, 2026 ABKB 98.

[35] *Supra* note 23.

I will focus here on the following provisions: the common s 1 on the reliance on provincial processes; the common s 3 on the decision to conduct a federal impact assessment; and the substitution (s 4 (Ontario)) and co-operative assessments provisions (s 4 (Alberta)).

Reliance on provincial processes, no impact assessment required

In each case, s 1(1) sets the tone for the entire agreement and there are no material differences between the Ontario and Alberta agreements. Here is the Alberta provision:

> When a proposed project is primarily within provincial jurisdiction, Canada will recognize Alberta as best placed to undertake an assessment and will rely on Alberta's environmental assessment or regulatory processes to assess the effects of the project including, as applicable, to address adverse effects within federal jurisdiction, as defined in the IAA, as outlined in this Agreement.[36]

I note that this language has evolved from some of the earlier agreements and now more stridently reflects a provincial perspective. Here, for example, is the opening section from the Prince Edward Island Agreement:

> When a proposed project is primarily a provincial undertaking, Canada is committed to relying on Prince Edward Island's applicable environmental assessment and regulatory processes for the assessment of the adverse effects within federal jurisdiction of a proposed project, to the greatest extent possible. (emphasis added to highlight some of the key differences between the two agreements)[37]

The opening phrase "a proposed project [that] is primarily within provincial jurisdiction" is not defined in any of agreements, but reference to s 1(2) of the agreements suggests that the parties likely intend that the term should be interpreted as everything other than interprovincial works or undertakings (although some of the agreements such as those with New Brunswick, Manitoba and Prince Edward Island, add to this other matters such as ports and nuclear projects) unless the project takes place on federal lands.

> 1(2) When a proposed project is or includes a federal work or undertaking or is on federal land Canada commits to integrating Alberta's environmental assessment and regulatory process requirements into the federal assessment, if applicable and desired by Alberta, as outlined in this Agreement.[38]

The terms used in the balance of s 1(1) of the Alberta agreement are startling in their absolutism and the absence of provisos: (1) *Canada will recognize* that Alberta is best placed to undertake, and (2) *Canada will rely* on Alberta's process to assess adverse effects within federal jurisdiction. The implications of this are massive. At the very least, it represents a clear political assertion that all future oilsands projects and coal mines should be subject to a provincial assessment to the exclusion of the federal assessment. Recall that this is the premise of option one described in the Background Paper, the early assessment plus federal protection option. The legal hook for implementing this option is s 16(2)(f.1) of the *IAA*. I will have more to say about this in the final section of the post.

Section 3(1) of the Alberta agreement "Decision-making about the conduct of a federal impact assessment" builds upon s 1(1) and commits the IAAC to avoid

> …duplicative decision-making processes related to assessments by relying on the provincial environmental assessment or regulatory processes in circumstances where Alberta confirms that those processes will address the adverse effects within federal jurisdiction…of projects that are primarily regulated by Alberta and/or there is a means

[36] *Supra* note 1 s1(1) [emphasis added].

[37] *Supra* note 14 [emphasis added].

[38] *Supra* note 1, s 1(2).

> other than impact assessment to address such effects, when making decisions about such projects as is reasonable after taking into account the factors under sections 9 and /or 16 of the IAA.[39]

While in this case the IAAC's commitment to avoid duplication is conditional, it is still startling to read that the condition depends upon the province's assessment that the province can handle the adverse effects within federal jurisdiction. This is especially problematic in light of criticisms as to the adequacy of the provincial impact assessment and regulatory processes as discussed above in the context of the preamble.

It is also startling when one compares this provision in the Alberta agreement with some of the earlier agreements, such as the Prince Edward Island agreement. The similar clause in that agreement is far less deferential to provincial interests and offers detailed guidance to ensure the protection of federal interests. The directions include, for example, the development of:

> …legally binding conditions in relation to the adverse effects within federal jurisdiction, including mitigation measures and follow-up program requirements, with which the proponent must comply.[40]

Substitution and substitution to a harmonized process

Let us assume that early decision-making has not resulted in the termination of the federal assessment process i.e. notwithstanding Canada's commitment in s 1(1), the Agency has made the determination that an impact assessment is required. At this point recall that the Background Paper identified two possible options that will leave the province in the driving seat, substitution and substitution to a harmonized process. While all of the other agreements refer to one or both of these substitution options, the word "substitution" is not even mentioned in the Alberta agreement.

Before looking at how the Alberta agreement deals with these issues, I will examine the Ontario agreement. The Ontario agreement deals with both options together in s 4 entitled "Substitution to Ontario's process or a harmonized process". Section 4(1) of the Agreement indicates that Ontario will endeavour to assess whether it wishes to trigger either s 31(1)(a) or (b) of the *IAA* no later than 10 days after IAAC has made its s 16 determination. Section 4(2) of the Ontario Agreement addresses how such a request will address federal concerns:

> (2) The request would confirm how the provincial assessment process on its own, or together with an arrangement between IAAC and [the relevant provincial authority], will meet the requirements of subsection 33(1) of the IAA. Such arrangement would document the roles, responsibilities, activities and timelines that will lead to a single assessment process that meets the legislative requirements of both Parties for the assessment of effects of the project and would constitute an arrangement for the proposed project pursuant to subsection 114(1)(f) of the IAA, as required under subsection 31(1)(b) of the IAA.[41]

In my opinion, the approach in the Ontario agreement tracks the provisions of the *IAA* quite closely. It also anchors the details of any additional implementing arrangement in s 114 of the Act. I refer to s 114 agreements in more detail in the final section of this post. I am not in a position to assess whether s 4(2) does the same for Ontario's assessment legislation.

Finally, s 4(3) addresses the implications of substitution for the duty to consult affirming that each party will "retain the responsibility to ensure that the duty to consult and, where appropriate, accommodate Indigenous Peoples has been satisfied."

The Ontario agreement builds on this solid statutory foundation in s 5 "Co-ordination of Potential Assessment conditions &

[39] *Ibid*, s 3(1) [emphasis added].

[40] *Supra* note 13, s 3(2)(e).

[41] *Supra* note 10, s 4(2).

decision-making and permitting"[42] which, as the title suggests, is designed to address co-ordinated decision-making at "the conclusion of a substituted or harmonized assessment"[43]. The parties will work together to "minimize duplication and regulatory burden"[44] to the extent possible seek to align such matters as "descriptions of the applicable project, reporting and notification requirements, terminology and definitions, and deadlines…"[45]

As noted above, the Alberta agreement does not even mention substitution. Instead, the agreement adopts (s 4) a more general statement of "Co-operative Assessments".

> Notwithstanding clauses 1(1) and (2), in the event both federal and provincial assessments may apply to a proposed project, the parties are committed to avoiding duplicative processes. In such circumstances IAAC and the applicable Alberta Regulator will develop an arrangement, including roles, responsibilities, activities and timelines that would lead to a single assessment process that would meet the legislative requirements of both jurisdictions. The proposed arrangement will be reviewed and considered by the President of IAAC and the Deputy Minister-level head of the relevant Alberta Regulator.[46]

In my opinion, this provision is far too general. It fails to ground the co-operative process within the text of the *IAA* and instead promises that any implementing "arrangement" will meet the legislative requirements of either jurisdiction.

The clause does not address the duty to consult issues but the Agreement returns to this in s 7 of the Alberta agreement, "Indigenous Peoples" which provides in part that "Canada will recognize Alberta as best placed to consult with Indigenous Peoples…in relation to the effects of relevant provincial decisions on the rights of Indigenous peoples"[47] at least where "a proposed project is primarily within provincial jurisdiction"[48]. Unlike the Ontario agreement, however, this section fails to address how the duty to consult will be addressed in the context of federal powers.

Each Crown or order of government is responsible for the duty to consult and accommodate with respect to decisions that fall within its jurisdiction that may affect Indigenous rights. While the Crown may delegate the administrative aspects of the duty to consult to others (e.g. corporations or even another order of government) it cannot delegate the duty to satisfy itself that it has met its obligations with respect to its own powers.[49] Reliance on Alberta's consultation efforts is perhaps even more suspect given ongoing litigation challenging the adequacy of Alberta's approach to consultation more generally.[50]

The Alberta agreement contains a co-ordinated decision-making clause which has similar content to that of the Ontario agreement, but, because the Alberta agreement refuses to use the language of substitution, it lacks a clear starting point in a unified process. Instead of beginning with "at the conclusion of a substituted or harmonized" it begins with a different premise:

> 6(1) <u>In the event that both federal and provincial assessments apply</u> to a proposed project, IAAC and the applicable provincial public interest decision-maker or regulatory approval decision-maker(s)…[51]

[42] *Ibid*, s 5.
[43] *Ibid*, s 5(1).
[44] *Ibid*, s 5(2).
[45] *Ibid*.
[46] *Supra* note 1, s 4(1).
[47] *Supra* note 1, s 7(1).
[48] *Ibid*.
[49] *Squamish Nation v British Columbia (Environment)*, 2019 BCCA 321.
[50] *Mikisew Cree First Nation v Alberta*, 2025 ABCA 304.
[51] *Supra* note 1, s 6(1) [emphasis added].

In my opinion, the failure to locate a joint approach within the text of the *IAA* will lead to additional regulatory uncertainty, one of the evils that these co-operation agreements are designed to address. Indeed, it makes s 6 incoherent insofar as its premise is parallel federal and provincial processes: "In the event that both federal and provincial assessments apply…"[52]

It is hard to say why the Alberta agreement declines to anchor the agreement within *IAA* text. Perhaps it has something to do with Alberta's second reference case[53] challenging the validity of the *IAA* on the basis that the 2024 amendments[54] did not go far enough. But any concerns of the province that specific references to *IAA* provisions might perhaps constitute provincial endorsement of the federal legislation are surely adequately addressed by another provision in the agreement:

> The Parties acknowledge that Alberta is challenging the constitutionality of the IAA, which is a matter before the courts. By entering into this Agreement, Alberta does not acknowledge the IAA is constitutional.[55]

THE LEGAL SIGNIFICANCE OF THE ALBERTA/CANADA COOPERATION AGREEMENT

It is useful to begin with some basic principles about intergovernmental agreements.

Intergovernmental Agreements: Basic Principles

Intergovernmental agreements are a routine part of the machinery of cooperative federalism. For an annual listing of Alberta's intergovernmental agreements see: Inventory of International and Intergovernmental Agreements[56]. Governments are free to enter into intergovernmental agreements without legislative sanction unless the jurisdiction has enacted more specific requirements.[57] An intergovernmental agreement may be binding or non-binding, depending upon any governing legislation and depending also on whether the agreement evinces an intention to create legal relations. An intergovernmental agreement cannot change the law, or create rights and obligations for third parties, unless the agreement has been ratified by statute and the statute confers objective legal effect on the agreement (e.g. a provision to the effect that "the agreement scheduled to this Act takes effect as if enacted in this Act"). But even when non-binding, an intergovernmental agreement may represent a statement of policy that forms part of the context for interpreting and informing the reasonable exercise of discretionary powers. There is an important proviso to this proposition however: the agreement must not fetter the discretion of a statutory decision-maker.

Application of the Principles to the Canada/Alberta Agreement

As noted above, governments may freely enter into intergovernmental agreements at the executive level unless somehow restricted by statute. The question for present purposes (and focusing on the federal side of things) is whether there is anything in the *IAA* that restricts Canada from entering into an agreement such as the Canada/Alberta agreement, specifically provisions such as s 1(1) and ss 4 and 6.

AUTHORITY FOR THE AGREEMENT

The *IAA* provides the Minister with broad authority to enter into agreements with provinces with respect to impact assessment. Specifically, s 114(1) empowers the Minister to:

> (c) enter into agreements or arrangements with [inter alia a

[52] *Ibid*.

[53] *Reference re Impact Assessment Act (Canada)*, 2025 ABCA 401.

[54] *Budget Implementation Act*, 2024, No. 1, SC 2024, c 17.

[55] *Supra* note 1, s 10(2).

[56] Alberta, Executive Council, *Inventory of International and Intergovernmental Agreements* (Edmonton: Open Government, last modified 18 December 2025), online: Open Government <open.alberta.ca/publications/inventory-international-intergovernmental-agreements>.

[57] For Alberta *see Government Organization Act*, RSA 2000, c G-10, s 11.

> province]…respecting assessments of effects;
>
> …
>
> (f) enter into agreements or arrangements with any jurisdiction for the purposes of coordination, consultation, exchange of information and the determination of factors to be considered in relation to the assessment of the effects of designated projects of common interest;[58]

This section does not tell us about the legal effect of these agreements, but s 114(1)(f) is cross-referenced several times in s 33(1) — the section of the Act that establishes the minimum conditions for substitution or harmonized assessment. Section 33 is thus a more specific provision addressing how Ministerial agreements under s 114 may be used.

The question for present purposes is whether ss 33 and 114 read together provide a complete code for co-operative assessments — and agreements relating to the same? It can be argued that these sections channel intergovernmental harmonization agreements towards substitution and harmonized assessment, and establish conditions for those arrangements. The Ontario agreement observes this channeling; the Alberta agreement does not. Instead, s 4 of the Alberta agreement, "co-operative assessments", is much more general, and, as I have repeatedly observed, fails to even mention substitution. In that sense it looks like an attempt to do an end run around ss 31 and 33 of the *IAA*. The answer to that may be that the conditions referenced in these sections, and in particular s 33, would necessarily have to be included in any cooperative arrangement negotiated under s 4, but the absence of any specific reference to the anchoring provisions of the *IAA* is troubling.

Fettering the Discretion of a Statutory Decision-Maker

There is a general principle of administrative law that discretionary powers must be exercised by the statutory delegate on whom the power is conferred. A delegate that fails to exercise that discretion independently (perhaps because of a ministerial direction) acts unlawfully, or to put the point in more modern terms, makes a decision that is prone to review on reasonableness grounds.[59] Section 153(2) of the *IAA* provides that while the Minister is responsible for the Agency "The Minister may not, except as provided in this Act, direct the President of the Agency or its employees, or any review panel members, with respect to a report, decision, order or recommendation to be made under this Act."

The question for present purposes therefore is whether the Agreement, or specific provisions of the Agreement, can be construed as an unlawful fettering of discretionary powers vested in the Agency (or some other statutory decision-maker) by the *IAA*. Alternatively, can any of the provisions of the Agreement be construed as an unlawful direction by the Minister under s 153(2) of the *Act*.

Rather than considering all of the provisions of the Agreement, I will focus attention on s 1(1) of the Agreement given the central role that this provision may play in ensuring that a federal impact assessment may not be required. Here, once again, is the text of s 1(1):

> When a proposed project is primarily within provincial jurisdiction, Canada will recognize Alberta as best placed to undertake an assessment and will rely on Alberta's environmental assessment or regulatory processes to assess the effects of the project including, as applicable, to address adverse effects within federal jurisdiction, as defined in the IAA, as outlined in this Agreement.[60]

[58] *Supra* note 7, s 114(1).

[59] *Canada (Minister of Citizenship and Immigration) v Vavilov*, 2019 SCC 65 esp at para 108. *See also Kanthasamy v Canada (Citizenship and Immigration)*, 2015 SCC 61 at paras 32 et seq and *Stemijon Investments Ltd v Canada (Attorney General)*, 2011 FCA 299 at para 24.

[60] *Supra* note 1, s 1(1).

The Agreement does not provide an express statutory anchor for this provision, but if one reads this section in the context of the Background Paper, it makes sense to connect this commitment ("Canada will recognize") to the power and duty of the Agency under s 16(1) of the Act to determine whether an impact assessment of a designated project is required. In making that determination, the Agency is directed to take account of a non-exhaustive list of factors, including a factor added in the 2024 amendments to the Act, namely s 16(2)(f.1):

> (f.1) whether a means other than an impact assessment exists that would permit a jurisdiction to address the adverse effects within federal jurisdiction — and the direct or incidental adverse effects — that may be caused by the carrying out of the designated project[61]

The question for present purposes is whether s 1(1) effectively fetters the Agency's discretion or whether it can be interpreted as a direction (not authorized by the statute) to give additional weight to one among a number of different relevant considerations.

Any evaluation of these arguments needs to take account of the "no-fettering" provisions in the Agreement i.e. provisions that are designed to say that "although such and such a clause may look like an attempt to fetter a discretionary power you are not allowed to read it that way."

There are two such "no-fettering" provisions in the Alberta agreement. The first is a general "no fettering" provision in s 10, "Application of this Agreement". This provision has been included in all of the co-operation agreements concluded to date:

> 10(3) This Agreement does not create or alter any power or duty under any enactment of Canada or Alberta and is not intended to direct or fetter the exercise of such powers or duties.[62]

The second such provision is found in s 11, titled "Issues Management" (a very "Alberta" title I think). This provision, effectively a dispute settlement clause, concludes with the following statement:

> IAAC and the applicable Alberta Regulator recognize that this issue management process does not fetter the authority of IAAC under the IAA or of Alberta under the EPEA.[63]

It is somewhat curious that the purported "recognition" represents the recognition of the IAAC and the applicable Alberta Regulator – neither of which is a party to the Agreement.

While such clauses may offer some cover to a provision such as s 1(1), I do not think that a court would regard them as conclusive. Nor will such clauses insulate a s 16(1) decision from a searching reasonableness review, and here I note that "The Agency must post a notice of its decision and the reasons for it on the Internet site." (*IAA*, s 16(3)) All that said, it is typically difficult to establish a case of fettering of discretion, particularly in the context of competing policy directions and issues of intergovernmental agreements and co-operative federalism.[64] Much may depend on the particular facts and perhaps a pattern of behaviour that involves rote reliance on s 16(2)(f.1). In other words, it will be difficult to attack s 1(1) at the outset on the basis of a fettering argument; instead, we shall have to wait and see to what extent the section influences Agency decision-making over time.

CONCLUSIONS

The Background Paper suggests that a central goal of these co-operation agreements is to achieve "one project, one review", which should of course beg the question of when anybody last saw separate (as opposed to joint) reviews of the same project? In fact, the number of federal

[61] *Supra* note 7, s 16(2)(f.1).

[62] *Supra* note 1, s 10(3).

[63] *Supra* note 1, s 11(4).

[64] See, for example, *Moresby Explorers Ltd v Canada (Attorney General)*, 2001 CanLII 780 (FCT).

panel assessments has been declining for years.[65] But while the "one project, one review" framing may be a solution to a non-problem, we can perhaps all agree that coordinated assessments of significant projects should be encouraged. In my view, for example, the JRP process[66] for the original Grassy Mountain Project provides an excellent example of a coordinated approach. While neither the proponent nor the provincial government may have liked the result, the JRP report provided a robust assessment that fulfilled statutory responsibilities under both federal and provincial legislation. It was and is a model of co-operation.

But the terms of co-operation for project assessment matters. The Grassy Mountain JRP was a mutually respectful process. The terms of co-operation proposed in the draft Alberta/Canada agreement are not. Instead, the agreement places far too much faith in provincial impact assessment and regulatory processes, processes that many consider to be inadequate — both in terms of substance and rigour and in terms of opportunities to participate. The terms of co-operation must also respect statutory obligations and in this case, the deference that the s 1(1) agreement requires Canada to accord to Alberta's environmental and regulatory processes looks like an abdication of federal responsibility without the means to ensure that Alberta's regulatory processes will protect federal interests. While this same criticism can also be levelled at the co-operation agreements with other provinces, I think it is clear that the draft Alberta agreement takes federal abdication to new heights.

POSTSCRIPT

The two governments released the final[67] executed version of the agreement on April 2, 2026 (and see the Alberta press release here)[68]. My review of the two documents suggests that there is only one change between the draft and the final with the inclusion of a new s 7(2) confirming that:

> For certainty, Canada will continue to consult with Indigenous Peoples on its decisions under the IAA, pursuant to its policies and practices.[69] ■

[65] *See* Canada, Minister's Advisory Council on Impact Assessment, *Third Report to the Honourable Julie Dabrusin, Minister of Environment and Climate Change* (2025), online (pdf): <open.canada.ca/data/en/info/ecd245f4-6d4d-4660-b478-7301fbbbfcb8>.

[66] *Supra* note 27.

[67] Canada and Alberta, *Co-operation Agreement between Alberta and Canada on Environmental and Impact Assessment* (last modified 2 April 2026), online: <canada.ca/en/impact-assessment-agency/corporate/acts-regulations/legislation-regulations/canada-alberta-cooperation-agreement.html>.

[68] Government of Alberta, "Final Agreement Signed for Major Project Reviews" (2 April 2026), online: <alberta.ca/release.cfm?xID=9595512DD9E9A-AFC3-7066-E533D12DA0A6EB8A>.

[69] *Supra* note 67, s 7(2).

THE STATE OF ENERGY IN QUEBEC

*Pierre-Olivier Pineau**

Quebec is the fourth largest energy-producing province after Alberta, British Columbia and Saskatchewan, and the third largest overall consumer after Ontario and Alberta according to 2024 data[1]. However, its energy mix is quite different from that of Canada's other provinces. Unlike Alberta, British Columbia and Saskatchewan, Quebec does not produce hydrocarbons. Nor does it generate any nuclear energy, which Ontario and, to a lesser extent, New Brunswick do. Hydroelectricity is what characterizes Quebec when it comes to energy production. More than 50 per cent of Canada's hydroelectricity is produced in Quebec, which also produces close to 25 per cent of Canada's wind energy[2]. This article provides an overview of energy in Quebec along three major axes: (1) energy profile; (2) the energy sector; and (3) tomorrow's challenges.

ENERGY PROFILE

Even though its hydroelectricity and wind energy production make Quebec the top renewable energy producer in Canada, more than 50 per cent of its energy consumption nonetheless rests on hydrocarbons: 36 per cent refined petroleum products, 14 per cent natural gas, and around 1 per cent propane and other forms of liquefied natural gas, as well as coal[3]. All of those hydrocarbons come from outside Quebec. Electricity (41 per cent) and biomass (8 per cent) top up the consumption. Graph 1 illustrates this profile, excluding biomass which is not included in Statistics Canada's detailed statistics.

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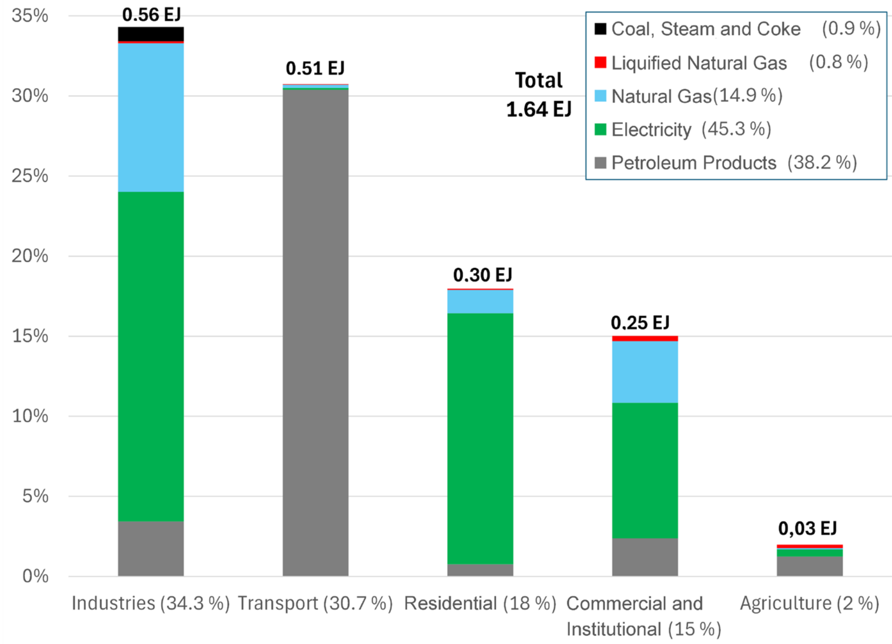
[1] Statistics Canada, *Supply and demand of primary and secondary energy in terajoules*, Table 25-10-0029-01 (2025).

[2] Statistics Canada, *Electric power generation, monthly generation by type of electricity*, Table 25-10-0015-01 (2025).

[3] Johanne Whitmore & Pierre-Olivier Pineau, *L'état de l'énergie au Québec 2026* (Montréal: Chaire de gestion du secteur de l'énergie, HEC Montréal, 2026).

Graph 1: Quebec's energy profile (biomass not included), with percentage of total demand, 2024[4]



Petroleum products

Although all of the hydrocarbons are imported, Quebec has two major refineries: Valero in Lévis (with a 265,000 barrels per day capacity), and Suncor in Montréal (137,000 barrels per day)[5]. Both refineries are next to the St. Lawrence River and close to pipelines. This strategic positioning enables them to receive crude oil from several sources and to distribute their production to several markets. The total refining capacity of slightly over 400,000 barrels a day is greater than the consumption of refined petroleum products in Quebec, which has held steady at less than 350,000 barrels a day for several years.

Petroleum products remain truly significant only for transportation, where they represent almost all of the energy consumed. In the transportation sector (30.7 per cent of the province's consumption), road transportation dominates, with 24.2 per cent of the province's energy, compared to 4.8 per cent for air, 1 per cent for maritime, 0.4 per cent for rail and 0.1 per cent for pipelines.

Although electric vehicle sales (EVs being battery electric vehicles and rechargeable electric hybrids) have come much farther in Quebec than elsewhere in Canada, gasoline and diesel consumption has not fallen and remains stable. They have been in the range of 9 billion and 3 billion litres annually since 2016[6].

In 2024, Quebec's automobile fleet had the highest proportion of EVs at 4.8 per cent compared to the Canadian average of 2.6 per cent[7]. Gasoline sales come to around 1,000 litres annually per inhabitant, which is equivalent to the volume sold per inhabitant in Ontario, and slightly less than the Canadian average of close to 1,100 litres. Annual diesel

[4] *Supra* note 1.

[5] Canadian Fuels Association, "Fuel Production" (last accessed 7 May 2026), online: <canadianfuels.ca/industry-facts/conventional-fuels/fuel-production>.

[6] Statistics Canada, *Sales of fuel used for road motor vehicles, annual*, Table 23-10-0066-01 (2025).

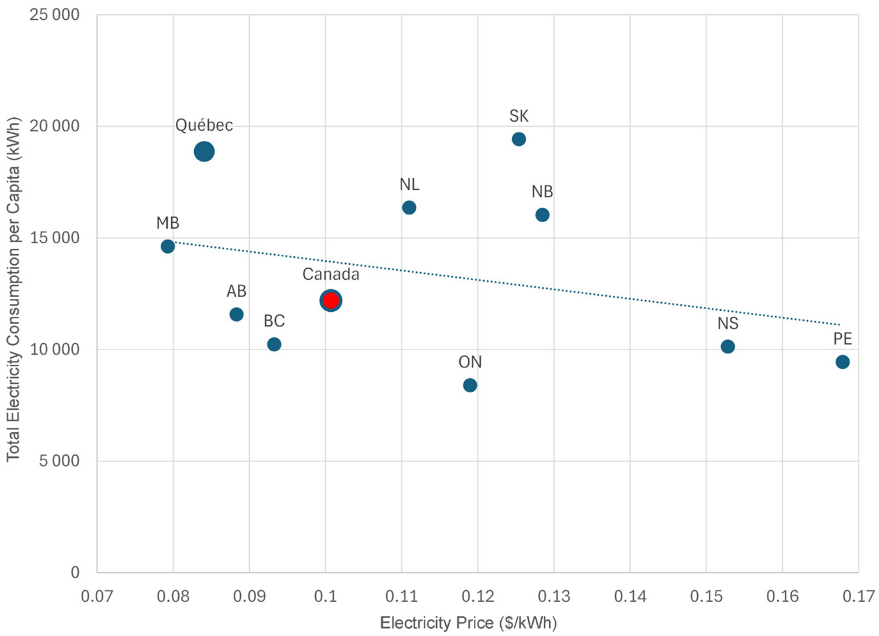
[7] Statistics Canada, *Vehicle registrations, by type of vehicle and fuel type*, Table 23-10-0308-01 (2025).

sales per inhabitant were 340 litres in 2024, below the Canadian average of 415 litres.

Electricity

Of all the provinces, Quebec is the one with the highest penetration of electricity. With more than 40 per cent of final consumption provided by this form of energy, the province is well above the 24 per cent, on average, characterizing the rest of Canada[8]. As illustrated in Graph 2, Quebec has a very high consumption of electricity per inhabitant, with one of the lowest kilowatt-hour ("kWh") prices in Canada[9]. With its population of 9 million inhabitants (compared to 16 million in Ontario and close to 6 and 5 million in British Columbia and Alberta), Quebec's electricity consumption easily surpasses that of all the other provinces: 171 terawatt-hours ("TWh") in 2024, compared to 135 TWh for the second province in line, Ontario.

Graph 2: Total sales of electricity per inhabitant and per kilowatt-hour, 2024[10]



Clearly, the tremendous availability of hydroelectricity and its low price account for this high consumption. This translates into residential, commercial and industrial energy consumption being dominated by electricity. Thus, as Graph 1 illustrates, more than 50 per cent of the energy in these sectors comes from this source.

Natural gas

In Quebec, natural gas amounts to less than 15 per cent of total consumption, well below the 37 per cent for Canada, making this energy less of a central presence in the province's profile. Nonetheless, it remains significant for the

[8] This 24 per cent comes from Statistics Canada, *Supply and demand of primary and secondary energy in terajoules*, *see supra* note 1. It should be noted that biomass is not included in these energy statistics even though it represents more than 5 per cent of consumption according to the International Energy Agency, online: <iea.org/countries/canada/energy-mix>. Thus, in reality, the proportion of electricity is less.

[9] Statistics Canada, *Electric power, electric utilities and industry, annual supply and disposition*, Table 25-10-0021-01 (2025).

[10] Statistics Canada, *Supply and demand of primary and secondary energy in natural units*, Table 25-10-0030-01 (13 November 2025).

industrial sector and in buildings, particularly commercial and institutional buildings.

Renewable natural gas ("RNG") production is on the rise in Quebec, with 124 million cubic metres ("m^3") in 2024, whereas 10 years earlier[11] it was nonexistent. It represents 2 per cent of the 6,195 million cubic metres consumed.

Biomass

As in the rest of Canada, Quebec's biomass sector lacks visibility, particularly because it is largely excluded from the energy statistics released by Statistics Canada. However, Natural Resources Canada reports that in 2023, firewood accounted for 12 per cent of residential consumption, as well as 12 per cent of industrial consumption (wood waste and black liquor)[12].

Liquid biofuels are also produced in Quebec, dominated by Greenfield Global, which owns a plant with a capacity of 200 million litres annually, turning corn into ethanol. Small producers of biodiesel (12 million litres annually) and pyrolysis oil (16 million litres annually) contribute to the production of liquid biofuels[13]. But this production remains marginal compared to total annual consumption of approximately 20 billion litres of petroleum products. In 2024, Quebec imported 1.2 billion litres of biofuel[14] to meet minimum ethanol and biodiesel content obligations for gas and diesel.

THE ENERGY SECTOR

As with most of Canada's provinces, Quebec's energy sector is essentially organized around two rather traditional models: the competitive petroleum products sub-sector and the largely regulated electricity sub-sector. Between petroleum products and electricity lies the natural gas sub-sector, which combines a higher level of competition for the energy component with highly regulated transportation and distribution services. Finally, there is the biomass sector, which is fragmented, with little structure or regulation.

Graph 3 illustrates the main institutions and key players in Quebec's regulated energy sub-sectors. The ministère de l'Économie, de l'Innovation et de l'Énergie ("MEIE") plays an important role as the department responsible for Hydro-Québec, the Crown corporation in charge of the electricity sector. It is also responsible for appointing the commissioners of the Régie de l'énergie, the administrative tribunal that sets the rates for electricity and for natural gas distribution. The MEIE also seeks to provide clearer direction to the energy sector with its recent Bill 69, passed in June 2025. The Bill calls for the establishment and implementation of an integrated energy resource management plan. That plan aims to orchestrate the different energy players to lead Quebec to carbon neutrality.

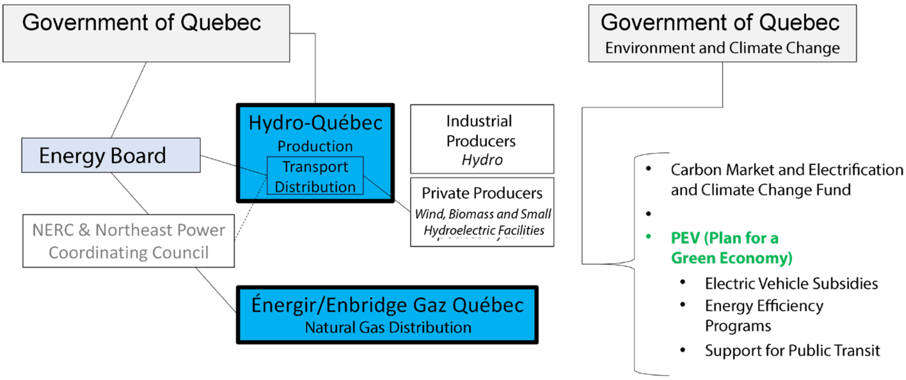
[11] Statistics Canada, *Supply and demand of primary and secondary energy in natural units*, Table 25-10-0030-01 (2025).

[12] Natural Resources Canada, *Comprehensive Energy Use Database* (2025).

[13] *Supra* note 3.

[14] *Supra* note 10.

Graph 3: Key institutions and players in Quebec's energy sector



The ministère de l'Environnement, de la Lutte contre les changements climatiques, de la Faune et des Parcs ("MELCCFP") plays a key but less direct role in the energy sector. That role is exercised through carbon pricing and the energy efficiency programs it deploys. Its actions directly affect the use of petroleum products and natural gas through the additional cost tagged onto their price in the carbon market, known as the cap-and-trade system ("SPEDE") applied to greenhouse gas ("GHG"). It is also the department responsible for the Plan for a Green Economy ("PEV"), Quebec's electrification and climate change policy framework designed to help achieve the province's climate goals.

The following sub-sections provide an overview of the situation in which the four main energy sub-sectors find themselves.

Petroleum products

The petroleum products market is fully open to competition. Crude oil is shipped to refineries according to the type of transportation chosen by the refiners — pipeline, ship or train. The price of that crude oil is freely set by the market. However, pipeline user fees are monitored by the Canada Energy Regulator to ensure there is no abuse of market power and that services are fair, reasonable and non-discriminatory.

Refiners sell their production to petroleum product distributors, which have the option of importing those products. The price of each petroleum product is set by the market.

However, since 2015, petroleum product distributors have been subject to SPEDE. They must obtain GHG emission rights equivalent to that which will be released into the atmosphere by the combustion of those products. Thus, in 2021-2023, petroleum product emitter-distributors such as Harnois, Irving, Norcan, Imperial Oil, Shell Canada Products, and others had to purchase emission rights to cover the emission of 117 million toness ("Mt") of GHG related to the combustion of their products[15]. At approximately $40/tonne, that corresponds to $4.7 billion. This cost of carbon added 8.4 ¢/litre to the price of gasoline.

The selling price of petroleum products is monitored by the Régie de l'énergie du Québec, but is not regulated. There used to be a threshold price to protect independent service stations, but it was abolished in June 2025 with the passage of Bill 69. That Bill did increase the transparency of pricing by service stations. They are now required to disclose the selling prices of gasoline and diesel to the Régie de l'énergie, which posts that information in real time for all service stations in Quebec.[16]

[15] Ministère de l'Environnement, de la Lutte contre les changements climatiques, de la Faune et des Parcs (Québec), *Rapport de couverture des émissions de la période 2021-2023 du système de plafonnement et d'échange de droits d'émission de gaz à effet de serre (SPEDE) du Québec*, report released on (December 6, 2024, updated on October 14, 2025).

[16] Gouvernement du Québec, *Régie Essence Québec* (last accessed 7 May 2026), online: <regieessencequebec.ca>.

Electricity

The Quebec government is far more involved in the electricity sub-sector. Hydro-Québec is a Crown corporation with a monopoly over hydro production by projects generating more than 50 megawatts ("MW") unless production rights have been assigned to industrial producers (as is the case with Rio Tinto). Hydro-Québec also has a monopoly on electricity transmission and distribution. It should be noted that 10 municipal distributors or cooperatives co-exist with Hydro-Québec. Those distributors were not nationalized in 1962, when 11 private distributors were put under the control of Hydro-Québec[17]. However, they are much smaller and only serve 170,000 customers compared to the more than 4.4 million customers served by Hydro-Québec.

Electricity production in Quebec is not regulated, and neither is the price of electrical energy sold to Hydro-Québec. However, it is the sole buyer that must ensure the electricity supply for its industrial, commercial and residential customers. The rates offered to Hydro-Québec customers are regulated by the Régie de l'énergie.

Hydro-Québec, as part of its distribution activities, has four sources of electricity:

1. **Heritage pool.** A 165 terawatt-hour ("TWh") heritage pool at a price set under the Act respecting the Régie de l'énergie is available to Hydro-Québec. The price is indexed annually to inflation, and in 2025 came to approximately 3.3 ¢/kWh[18].

2. **Post-heritage contracts.** Given that Quebec's requirements exceed 165 TWh, Hydro-Québec has signed long-term supply contracts, known as post-heritage, with itself (Hydro-Québec, in its production activities) and with private producers. Those contracts supplied 18 TWh in 2025 at an average cost of 11.7 ¢/kWh.

3. **Short-term purchases.** Hydro-Québec also buys electricity from neighbouring markets such as Ontario, New York, New England and New Brunswick. These spot purchases amount to a few TWh. In 2025, they were purchased at an average cost of 13.4 ¢/kWh.

4. **Demand management.** Finally, Hydro-Québec has demand management tools (interruptible options, dynamic pricing) it can use with its customers, enabling it to reduce its supplies in return for compensation, lower than short-term market prices.

Thus, the rates charged to customers, approved by the Régie de l'énergie, consist of these electricity supply costs (not regulated by the Régie de l'énergie), transmission costs (regulated) and distribution costs (regulated). For the transmission and distribution costs, investments must be approved, particularly those associated with energy efficiency.

The rate structures used by Hydro-Québec are very simple:

- a daily fixed rate (residential or small commercial customers) or a demand charge, based on the maximum power in kW used in a month (commercial and industrial customers); or

- a price per kWh consumed, with a second higher price range for residential customers and a second lower price range for commercial customers. Industrial customers have only one price per kWh.

Some customers choose optional dynamic rates, and different rate options exist for certain cases. As illustrated in Graph 2, the dollar value of kWh sold by Hydro-Québec is among the lowest in Canada, reflecting the relatively low price enjoyed by customers.

Cross-subsidization reduces the rates paid by residential customers by almost 20 per cent, to the detriment of commercial customers which

[17] Hydro-Québec, "1960–1979 — The Second Phase of Nationalization", online: <hydroquebec.com/history-electricity-in-quebec/timeline/second-nationalization.html>.

[18] Hydro-Québec Distribution, « Tableau 3 Coût des approvisionnements », Approvisionnement en électricité, HQD-2, Document 1, Régie de l'énergie dossier R-4307-2025 (31 July 2025).

pay 27 per cent more than would be justified by their service costs. Industrial customers pay approximately 15 per cent more than would be justified by their service costs.[19]

Hydro-Québec, in its production activities, is also a very active player on the American northeast electricity scene. It takes advantage of its enormous reservoirs, which can hold up to 176 TWh of energy, and of its central position between the open markets in Ontario, New York and New England for electrical energy transactions. Two major 10 TWh per year long-term export contracts have been signed with Massachusetts (20 years) and New York (25 years). Those contracts led to the construction of two new transmission lines to those states, which will be commissioned in 2026.

Natural gas

Énergir is the largest natural gas distributor in Quebec. It covers the greater Montréal area to Québec, as well as southern Quebec and an extension to Lac St-Jean. It delivers natural gas to some 210,000 customers. The Gatineau area, in the Outaouais, has its natural gas needs met by Enbridge Gaz Québec through a separate system that supplies just over 40,000 customers[20].

Major customers (consuming more than 7,500 m^3 annually) can choose their natural gas supplier. Different companies sell natural gas that they purchase on the North American market.

The two natural gas distributors bill customers for distribution, transportation and supply if they have not opted for another supplier. In addition to those costs, there are SPEDE costs, as for petroleum product distributors. On December 1, 2025, the price of carbon, which is adjusted every quarter, represented 8.587 ¢/m^3[21].

Énergir customers can choose to purchase RNG rather than fossil natural gas. RNG costs more, but the fact that it is renewable exempts it from the purchase of emission rights under SPEDE. As of October 1, 2025, the price of RNG was 94.884 ¢/m^3 (equivalent to $25.04/GJ)[22]. By comparison, fossil natural gas sold for 15.308 ¢/m^3 ($4.04/GJ) on April 1, 2026[23].

Énergir is required to sell 5 per cent of RNG annually to its customers between 2025 and 2030, and that proportion will increase to 10 per cent in 2030. The volumes required to reach those targets, that were not voluntarily purchased by customers, are paid by customers through a socialization fee. That helps recover the higher costs of purchasing RNG. The Régie de l'énergie approves supply contracts that Énergir negotiates with RNG suppliers.

Biomass

Energy from biomass takes different forms: firewood, wood pellets, forest residues, ethanol and RNG. The suppliers of these products come from the agricultural sector, the agri-food sector, waste management, the forest industry and the intersection of these sectors.

The government's intervention in this sub-sector is very limited, except for renewable energy content obligations in natural gas, gasoline and diesel. The RNG issue is covered above. For gasoline and diesel, the Government of Quebec sets minimum volume proportions for low-carbon intensity content, which must be integrated into the total volume of gasoline or diesel distributed. Since 2025, these minimum proportions are 12 per cent for gasoline and 5 per cent for diesel, and will rise progressively

[19] Hydro-Québec Distribution, Annual Report – Information provided pursuant to Section 75.1 for 2024, HQD-2, Document 1, Régie de l'énergie dossier (22 April 2025, revised 26 May and 26 September 2025).

[20] *Supra* note 3.

[21] Régie de l'énergie (Québec), *Conditions de service, tarifs et informations pratiques d'Énergir*, online: Régie de l'énergie <regie-energie.qc.ca/fr/consommateurs/informations-pratiques/conditions-de-service-et-tarifs-denergir>.

[22] Énergir, "Choosing an RNG quantity is easy!", online: <energir.com/en/business/renewable-natural-gas/steps-and-tariff>.

[23] Énergir, "Pricing, Rates and Other Suppliers", online: <energir.com/en/business/customer-centre/billing-and-pricing/pricing>.

to 15 per cent and 10 per cent, respectively, in 2030[24].

These low-carbon intensity contents include[25]:

- biofuels such as ethanol and biodiesel;
- fuels produced from atmospheric CO_2 and green hydrogen such as e-diesel; and
- fuels produced by converting synthesis gas into hydrocarbons, such as renewable gasoline produced from non-recyclable plastic.

It should be noted that mandatory integration of low-intensity carbon content into gasoline and diesel fuel in Quebec is an obligation in addition to those under the federal Clean Fuel Regulations ("CFR"), and their reporting mechanisms are distinct.

TOMORROW'S CHALLENGES

Quebec's energy sector has two big things going for it. First, its tremendous capacity for producing low-cost renewable electrical energy. Second, an already high degree of electrification, which gives it a head start over other provinces in the economy's decarbonization.

All the same, the province is up against a number of significant challenges, summarized here as three major ones: reaching the GHG reduction targets, the evolution of the price of electricity, and the development of biofuels.

Reaching the GHG reduction targets

With 8.9 tonnes of GHG per inhabitant in 2023, Quebec is the province with the lowest emissions per person. It is also the province most open about its climate ambitions, aiming for a reduction of 37.5 per cent under the 1990 level by 2035 (in January 2026, the timeline was changed from 2030 to 2035[26]). With its carbon market (SPEDE) linked to California's, Quebec has established a binding mechanism that mechanically pressures GHG emissions. It is the only province in Canada that has an absolute ceiling on a large portion of its emissions (approximately 75 per cent). Only agriculture, waste and certain transportation modes (air and maritime) are not subject to SPEDE.

Yet, despite its current strong position and SPEDE, Quebec's GHG emissions reduction trajectory will not reach its target by 2035. The energy sector represents 70 per cent of its GHG emissions, so significant reductions will have to take place in this sector before its target is reached.

Despite the PEV and its different initiatives (see Graph 3), Quebec has still not managed to reduce its consumption of petroleum products or natural gas. No reforms are in sight for the transportation sector to make it more efficient and reduce its energy consumption. The same applies to buildings and industry: discussions are taking place around energy efficiency and electrification, but without any significant break from the past. Electrification is presented as the best way to decarbonize. Quebec already has a highly developed electricity sector. Will it be able to evolve it to decarbonize through electrification?

Evolution of the price of electricity and electrification

The low price of electricity in Quebec has pushed its penetration into heating for buildings and industry. Consequently, electricity consumption in Quebec is higher than elsewhere, and its electricity system is bigger. Hydro-Québec's objective for 2035 is to add 60 TWh of energy for new uses, which is a very ambitious target to reach in less than 10 years. This new capacity will cost far more than the electricity in the heritage pool: already the leap from heritage power (3.3 ¢/kWh) to post-heritage (11.7 ¢/kWh)

[24] Regulation respecting the integration of low-carbon-intensity fuel content into gasoline and diesel fuel, CQLR c P-30.01, r 0.1.

[25] Gouvernement du Québec, "Reporting on the integration of low-carbon-intensity content into gasoline and diesel fuel", online: <quebec.ca/agriculture-environnement-et-ressources-naturelles/energie/production-approvisionnement-distribution/carburant-faible-carbone>.

[26] Cabinet du ministre de l'Environnement, de la Lutte contre les changements climatiques, de la Faune et des Parcs (Québec), « Cible de réduction des GES : Québec maintient une cible ambitieuse, mais réaliste » [GHG reduction target: Quebec maintains an ambitious but realistic target] (22 January 2026), online: Gouvernement du Québec <quebec.ca/nouvelles/actualites/details/cible-de-reduction-des-ges-quebec-maintient-une-cible-ambitieuse-mais-realiste-68116>.

is enormous: more than 8 ¢/kWh! Users are nowhere near prepared to pay the marginal cost of production of new supplies. The setting of rates based on average cost is seldom challenged. Any increase in that average cost even triggers negative reactions–indeed, calls into question the projects causing the increases.

That amounts to a very poor price signal, pushing for overconsumption instead of true efforts towards energy efficiency.

Thus, Quebecers are blind to the real costs of electricity supply, even as a lot of new capacity would have to be added to electrify. That makes for a very weak economic foundation, which risks throwing off the current balance.

Biofuel development

Even with successful electrification and a reduction in needs that could be achieved through greater energy efficiency, gaseous and liquid biofuels will have their place in a decarbonized society. Certain uses are simply less conducive to electrification (utility/work vehicles, planes, certain industrial processes, etc.).

Thus, the energy system's resilience will benefit from a diversity of supply sources, even a degree of redundancy. In the event of a power failure, those biofuels will be invaluable.

Energy security and self-sufficiency will also benefit if biomass is promoted in shorter and/or circular circuits.

For all of these reasons, it would be important to develop a more coherent biofuel sub-sector. Quebec already has a number of biofuel producers, but the sector is fragmented and few players manage to succeed, even less secure a place, in any convincing way.

CONCLUSION

Quebec's energy profile stands out for its high proportion of renewable electricity and for stronger decarbonization ambitions than elsewhere in Canada. Nonetheless, the challenges it faces are quite similar: succeed in getting on a trajectory of GHG emission reduction aligned with its targets, reform its electricity market to give it more solid economic foundations, and boost biofuels to give them a chance to fully take their place.

A more extensive dialogue with the other provinces could help more quickly advance on those three fronts given that they are all facing the same issues. But first, a diagnostic more openly shared by Quebec's players would not be without value in enabling a more coordinated effort. ■

UTILITY ASSET DISPOSITIONS IN AN ERA OF CLIMATE CHANGE: WHO PAYS?

*Mark Kolesar**

Utility asset dispositions are a common recurring aspect of utility regulation. In the normal course, utilities invest in assets necessary for the provision of utility service, then these investments are depreciated or amortized over the life of the assets, and in this way the costs of the assets are gradually recovered in utility rates. At the end of an asset's useful life, the fully depreciated asset is removed from utility service and any ancillary costs, for example costs of removal or retirement net of salvage, are recovered in rates. But what happens when an asset's useful life is cut short? In this case, the asset is often referred to as a "stranded asset."

The "used and useful" standard is a foundational principle in Canadian public utility law that restricts cost recovery in rates to assets that are actively serving customers.[1] In the Canadian regulatory construct, stranded assets are assets that have not yet been fully depreciated but are no longer "used and useful" for the provision of utility service. When this happens, an asset's remaining unrecovered cost is no longer included in rate base and recovered from customers in the normal course. This raises the issue of how to dispose of the undepreciated balance of the stranded asset; and whether the balance is to the account of the shareholder, and therefore unrecoverable in rates, or to the account of customers and recoverable in rates.

The effects of climate change are renewing debates about the appropriate disposition of stranded assets because climate change is reshaping the operating environment for electric utilities in two ways. First, historical weather patterns are threatening facilities and making resilience a priority for grid planners. Second, regulatory and legislative directives in response to climate risk are placing new demands on utilities. The effects of climate and the resulting energy transition are increasing stranded asset risks. These risks are compounded by the long depreciation horizons of utility infrastructure, creating uncertainty about whether assets will be stranded in future and who will bear the financial burden if assets are destroyed, become underutilized, or are required to retire early.

Assuming a planning horizon that may encompass thirty to forty years, utilities can expect increased physical risks to their facilities, higher operating costs, and increased demands

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[1] There are limited exceptions to the strict application of the "used and useful" standard in Canadian utility regulation. Plant Held for Future Use ("PHFFU") is sometimes permitted to attract a regulated return until it is put into service, and Construction Work in Progress ("CWIP") is sometime included in Rate Base and permitted to earn a regulated return prior to completion and subsequent use in the provision of utility service.

for resilience and decarbonization.[2] Frequent and intense storms are already increasing the degree of damage to transmission and distribution assets. Wildfire risks are escalating; threatening utility infrastructure and increasing liability exposure for utilities when utility equipment sparks fires.[3] A McKinsey study highlights that investments in long-lived assets in risky locations increase balance-sheet exposure.[4] The destruction of utility assets due to volatile weather raises questions with respect to who should pay for the continued recovery of asset costs when they are destroyed by weather events.

Utilities are increasingly required to integrate climate risk into planning, undertake justifiable resilience investments, and demonstrate climate adaptation strategies; all while satisfying decarbonization objectives. Stranded asset risk increases when infrastructure built for historical or emerging climate and GHG norms becomes potentially inadequate or unsafe. Who should pay for the undepreciated costs of assets that are no longer required due to a lack of suitability in response to climate risk?

STRANDED ASSET ISSUES

Stranded assets in this emerging environment may chiefly come about in two ways. First, assets may become stranded when they are prematurely destroyed in climate-related events, such as wildfires and tornadoes. In these cases, the assets no longer exist physically, but the undepreciated and therefore unrecovered capital invested in the destroyed assets remains in the utilities' accounts. Second, facilities and infrastructure may become underutilized, uneconomic, obsolete, or unrecoverable under policy or legislative requirements to address climate risk. In this case, although the assets still physically exist, unrecovered capital invested in the now un-needed or unsuitable assets may no longer be recoverable in rates because the assets are no longer "used and useful" for the provision of utility service.

As climate and the ensuing energy transition increasingly affect utilities in Canada, regulators will need to grapple with several sometimes inter-related issues with respect to the disposition of assets potentially stranded as a result of climate events and climate policy. How can regulation mitigate the costs of stranded assets? How should the costs of stranded assets be calculated when stranding occurs? Who should bear the costs of stranding as a result of climate events or climate policies when they occur? Should stranded asset costs be equitably shared between utility shareholders and utility customers, and if so, how? How should the risk of stranded asset costs be accounted for in utility revenue requirements and rates?

THE CURRENT TREATMENT OF STRANDED ASSETS IN CANADA

The disposition of stranded asset costs in Canadian utility regulation is inconsistent across jurisdictions and occasionally muddled by the influence of government policy on regulators. Ontario and Alberta approaches to the disposition of stranded assets are, for example, quite different.

Assets Stranded by Climate Events

As a point of departure, it is worth considering the approach to the disposition of assets stranded by climate events in the two jurisdictions. Both the Ontario Energy Board ("OEB") and the Alberta Utilities Commission ("AUC") include Z factors in their regulatory rate setting frameworks to consider the costs of unforeseen events that are outside of management's control. Both jurisdictions have similar criteria for what constitutes a Z factor event. Qualifying events include climate events, such as tornadoes and wildfires. However,

[2] Canadian Electricity Association, *Adapting to Climate Change: State of Play and Recommendations for the Electricity Sector in Canada* (2016), online (pdf): <natural-resources.canada.ca/sites/www.nrcan.gc.ca/files/energy/energy-resources/Adapting_to_Climate_Change_State_of_Play_and_Recommendations_for_the_Electricity_Sector_in_Canada.pdf>.

[3] Notable examples in Hawaii, Alberta and California have led to the adoption of increased measures to reduce the potential for utilities to spark wildfires.

[4] Sarah Brody, Matt Rogers & Giulia Siccardo, "Why, and How, Utilities Should Start to Manage Climate-Change Risk" (2013), *McKinsey & Company*, online (pdf): <mckinsey.com/~/media/McKinsey/Industries/Electric%20Power%20and%20Natural%20Gas/Our%20Insights/Why%20and%20how%20utilities%20should%20[st]art%20to%20manage%20climate%20change%20risk/Why-and-how-utilities-should-start-to-manage-climate-change-risk-vF.pdf>.

although both jurisdictions generally allow for the recovery of incremental costs arising from a Z factor event, including allowing replacement assets in rate base, the disposition of the costs of assets stranded by the event has been different in the two provinces.

The *Ontario Energy Board Act*[5], at Section 36 and Section 78, gives the Board authority to set just and reasonable rates for gas utilities and electricity distributors and transmitters. The OEB's approach to considering stranded assets is grounded in the prudence test and, when weather events occur, application of a Z factor. Under the prudence test, if an investment was prudent when it was undertaken then the OEB has generally determined that the utility is entitled to recover both the remaining costs of the assets destroyed and the costs of replacement assets from customers. In this way, Ontario has largely assigned stranded asset liability for unforeseen climate events to utility customers.

The West Coast Huron Energy Inc. decision (EB-2011-0335)[6] is a seminal case in Ontario. West Coast Huron requested approval to recover the costs caused by a tornado that occurred in August 2011, destroying many of its assets in the town of Goderich. The application requested recovery of the remaining net book value of the assets destroyed. The Board found that a Z-factor event had occurred when the F3 tornado destroyed a significant portion of West Coast Huron's distribution system and other assets and that the event was genuinely "external to the regulatory regime and beyond the control of management."[7] The Board concluded that the event satisfied the causation, materiality and prudence conditions for a Z factor adjustment to the company's rates. Accordingly, the Board directed the company to:

> ...apply for a Z-factor adjustment in its next rebasing application when actual incremental costs and lost revenues have been clearly identified. The review would be limited to prudence, cost allocation and rate design matters since causation and materiality have been established in this Decision with Reason.[8]

The company's subsequent rebasing application was resolved by way of a settlement, set out in Settlement Agreement EB-2011-0335. The settlement approved by the OEB included $162,105 in revenue requirement for the net book value of stranded assets related to storm damages.[9]

In contrast to Ontario, Alberta's approach to stranded asset cost recovery is grounded in the Supreme Court's Stores Block decision[10] and governed by the AUC's Utility Asset Disposition ("UAD") decision.[11] The AUC strictly interpreted the Stores Block decision in the UAD decision, finding that ratepayers do not have a proprietary interest in the utilities' assets. Because the utilities own their assets, any gains or losses at disposition are to the account of utility shareholders. Losses from extraordinary retirements including premature obsolescence, policy-driven early retirement, and natural disasters have accordingly been generally borne by shareholders.

The UAD decision distinguishes between ordinary retirement of an asset at the end of its service life, and extraordinary retirement that results in stranded asset costs. An ordinary retirement is one that was reasonably contemplated by depreciation and amortization and for which the costs have been recovered over the asset's life in customer rates. An extraordinary retirement is one where an asset is removed from rate base before it is fully depreciated because it is obsolete, overdeveloped and surplus to future needs, used for non-utility purposes, removed due to unusual casualty or sudden and complete obsolescence, or unexpectedly

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[5] *Ontario Energy Board Act, 1998*, SO 1998, c 15, Sch B.

[6] Ontario Energy Board, *Notice of Application and Hearing for an Electricity Distribution Rate Change — West Coast Huron Energy Inc*, Decision and Order, EB-2011-0335.

[7] *Ibid* at 8.

[8] *Ibid* at 9.

[9] *Ibid*, Appendix O at 13.

[10] *ATCO Gas & Pipelines Ltd v Alberta (Energy & Utilities Board)*, 2006 SCC 4.

[11] Alberta Utilities Commission, *Utility Asset Disposition*, Decision 2013-417 (26 November 2013), online: AUC <auc.ab.ca/applications/decisions/Decisions/2013/2013-417.pdf>.

shut down completely due to events that were not reasonably anticipated or contemplated in the applicable depreciation and amortization provisions used to set rates. Any under or over recovery of capital investment resulting from an extraordinary retirement is to the account of the utility's shareholders. Customers do not share in any loss or gain on disposition of an asset.

On June 11, 2018, the Alberta Legislature passed Bill 13, *An Act to Secure Alberta's Electricity Future*[12], which amended several existing statutes. There was an attempt to address the regulatory implications of the Stores Block decision on utility asset dispositions in Alberta in the draft legislation, but the provisions were removed.[13] The effect of the UAD decision remained unchanged.

By way of example, in Decision 21609-D01-2019 *ATCO Electric Ltd., Z Factor Adjustment for the 2016 Regional Municipality of Wood Buffalo Wildfire*[14], the AUC denied ATCO recovery of the undepreciated value of the assets destroyed in the Wood Buffalo wildfire.[15] The Commission determined, pursuant to its UAD decision, that the utility and its shareholders were responsible for the remaining net book value of the assets destroyed.

However, a 2023 Alberta Court of Appeal ruling[16] granted an appeal of Decision 21609-D01-2019, finding that the decision under appeal was based on errors of law, particularly the conclusion that the Commission's options for treating destroyed assets were constrained by the Stores Block decision. The Court determined that the setting of rates is clearly within the discretion of the Commission, including the determination of what expenses can be included as recoverable costs, how to deal with depreciation, and how to deal with stranded or unpredictably destroyed assets. The court summarized its finding as follows:

> To summarize, the issue is where the losses resulting from forces of nature should fall: on the utility's consumers or on the utility's shareholders:
>
> (a) In legal terms the issue is where a just and reasonable tariff would place those losses, having due regard to the right of the utility to a reasonable opportunity to recover its prudent costs.
>
> (b) This issue was not decided by *Stores Block*...
>
> (c) The analysis cannot start with an assumption that it is inherently fair to place the burden on one group or the other. That is the answer, not the premise of the question.
>
> (d) It is relevant that the utilities stopped buying insurance to save the consumers money. The Commission apparently decided that it was prudent for the consumers to self-insure.
>
> (e) The answer does not lie in whether the loss was or was not anticipated in the survivor curve behind the depreciation schedules, or whether the loss was therefore ordinary or extraordinary.
>
> (f) The answer also does not arise from "fundamental property and corporate law principles" or property ownership of the destroyed

[12] *An Act to Secure Alberta's Electricity Future*, SA 2018, c A-14.5 (assented to 11 June 2018).

[13] The failed amendments to Bill 13 would have guaranteed that utilities would recover the full cost of any stranded assets in customer rates providing the original investment was determined to have been prudent. However, the amendments would also have modified the prudence test ostensibly in favour of utility shareholders. These amendments were eventually excluded from the legislation.

[14] *ATCO Electric Ltd, Z Factor Adjustment for the 2016 Regional Municipality of Wood Buffalo Wildfire*, Decision 21609-D01-2019.

[15] The author was a member of the panel of the AUC that issued *ATCO Electric Ltd, Z Factor Adjustment for the 2016 Regional Municipality of Wood Buffalo Wildfire*, Decision 21609-D01-2019.

[16] *ATCO Electric Ltd v Alberta Utilities Commission*, 2023 CanLII 129 (ABCA).

> assets. Loss by fire is not a part of disposition law.
>
> Ultimately the question lies within the discretion of the Commission, to be exercised consistently with the words of the *Electric Utilities Act*, having regard to all relevant considerations, while disregarding irrelevant ones.[17]

In Decision 28320-D01-2023[18] the AUC reconsidered its ruling in Decision 21609-D01-2019. In its reconsideration the Commission focused its analysis on whether ATCO had been provided with a reasonable opportunity to recover its costs, having accepted that the costs were prudently incurred and that the assets were required for the provision of utility service. On this question, the Commission concluded:

> ...in the circumstances of the Wood Buffalo fire, isolating and directing the removal of the entirety of the net book value of the destroyed assets had the effect of rescinding the reasonable opportunity previously afforded to ATCO Electric to recover these costs, and did so for reasons beyond ATCO Electric's control.[19]

ATCO was subsequently allowed to recover in rates the net book value of the assets destroyed in the wildfire.

Assets Stranded by Government Policy

Thus far, the Alberta Utilities Commission has strictly applied the UAD decision in circumstances where a company is replacing infrastructure in response to government policy. In an early application of the UAD decision, the AUC denied cost recovery to EPCOR for the stranded costs of meters replaced by Advance Metering Infrastructure ("AMI") meters, despite accepting that the adoption of AMI meters complied with government policy.[20]

In this case, EPCOR indicated that it had considered two government policy matters in its analysis of the AMI business case. First, EPCOR considered new Measurement Canada specification S-S-06 that introduced more stringent regulations regarding meter compliance sample testing and meter replacements.[21] Second, the company argued that its decision to acquire an AMI system to automate meter reading and associated meter processes was consistent with government policy in relation to smart meters.[22] The Commission accepted both policy initiatives as supportive of the company's decision to adopt AMI.[23] The Commission then conducted an analysis of whether retirement of the existing meters resulting from their replacement with AMI meters constituted an "ordinary retirement" or an "extraordinary retirement." The Commission concluded that because it was:

> ...not reasonable to conclude that the characteristics of the proposed retirement of EDTI's existing meters over a forecast three-year period were anticipated or contemplated in the determination of the parameters used in the preparation of EDTI's most recent depreciation review and reflected in EDTI's rates, the book value of the undepreciated meters is to the account of EDTI's shareholder.[24]

Accordingly, EPCOR was prevented from recovering in rates the outstanding net book value of the existing meter assets that would

[17] *Ibid* at para 60.

[18] Alberta Utilities Commission, *Reconsideration of ATCO Electric Ltd, Z Factor Adjustment for the 2016 Wood Buffalo Fire*, Decision 28320-D01-2023 (19 December 2023).

[19] *Ibid* at para 36.

[20] Alberta Utilities Commission, *2013 PBR Capital Tracker True-Up and 2014–2015 PBR Capital Tracker Forecast*, Decision 3100-D01-2015 at paras 639–91. The author was the chair of the AUC panel that issued Decision 3100-D01-2015.

[21] *Ibid* at para 645.

[22] *Ibid* at para 643.

[23] *Ibid* at paras 657–58.

[24] *Ibid* at para 691.

be retired, estimated to be approximately $10 million to $12 million.

It is yet to be seen whether the ruling in Decision 28320-D01-2023 will compel the AUC to revisit and reconsider its approach not only to assets destroyed prematurely by forces of nature but also to assets stranded prematurely by forces of government policy. The Commission was careful to ring fence its finding in Decision 28320-D01-2023, stating that:

> In arriving at this decision, the Commission has not adopted a new framework or test for the treatment of assets destroyed by force of nature. Instead, the Commission has based its decision on the relevant provisions of the Electric Utilities Act and the guidance of the Court of Appeal, as applied to the particular circumstances of the Wood Buffalo fire.[25]

The Challenge of Responding to Government Policy Objectives

Regulators may be inclined to respond to government policy objectives in their approach, recognizing a broad public interest mandate. However, how much weight should be given to government mandate letters or other policy instruments that are not given effect in the regulator's governing legislation? Responding to government policy objectives when policies are not adequately addressed in legislation can present difficulties for regulators. Where there is a gap between stated policy objectives and governing legislation that would give the regulator clear authority to achieve those policy objectives, regulators risk judicial appeals of their decisions on the one hand, and government rebuke or potential dismissal on the other.

The Nova Scotia Energy Board Decision 2026 NSEB 8[26] illustrates the challenges regulators face and the kind of creative workarounds they sometimes adopt to achieve a public interest outcome, when government policy and legislative mandates are not aligned.

The Government of Nova Scotia's Clean Power Plan[27] mandates, among other things, the phasing out of coal fired generation by 2030. In its September 18, 2025 general rate application, Nova Scotia Power stated that it intended "to request approval of the securitization of $704 million of the unrecovered net book value of thermal assets within the scope of the Decarbonization Deferral Account."[28] As explained and discussed further below, securitization reduces the cost of recovery for the net book value of stranded assets by replacing the utility's market-based current weighted average cost of capital with lower-cost bond financing to mitigate the effect on utility rates. However, in Nova Scotia securitization required enabling legislation and companion regulations that might not have been enacted in time for the company to implement approved rates on January 1, 2026; rates that would have included payments on the securitization bond had securitization been approved. In the alternative, the company requested that the Nova Scotia Energy Board approve a "securitization deferral" to defer the depreciation expense and financing costs of the unrecovered net book value of the thermal plant assets until the necessary legislation is enacted, at which time securitization would proceed. In its decision, the Board recognized that "securitization cannot currently proceed in Nova Scotia because the enabling statutory provision has not been proclaimed and regulations to implement this mechanism have not been enacted by the Province." [29] The Board approved the requested securitization deferral. A follow-on application would approve the securitization of the unrecovered net book value of the thermal assets and rates would be adjusted accordingly.

Regulators may be increasingly required to consider alternative approaches to deal with the potential for assets to be stranded by climate events or government policy initiatives

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[25] *Supra* note 18 at para 24.

[26] Nova Scotia Energy Board, *General Rate Application by Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges and Regulations*, Decision 2026 NSEB 8, M12451.

[27] Government of Nova Scotia, *Clean Power Plan*, online: <novascotia.ca/clean-power-plan>.

[28] *Supra* note 26 at para 285.

[29] *Ibid* at para 314.

while balancing competing objectives, such as affordability; particularly when government policy and legislative mandates are potentially at odds.

REGULATORY ALTERNATIVES

A survey of regulatory alternatives to manage both the potential for stranded assets and the disposition of stranded asset costs in jurisdictions throughout North America yields some alternative responses to stranded asset issues that are worthy of consideration and discussion.

Mitigating the residual cost of assets that may be stranded due to climate change

If the likelihood and potential severity of stranded asset costs can be reduced before any assets are stranded, then the effect of stranded assets on utilities and their customers can be constrained over the long run. However, regulators are increasingly challenged to balance the need to mitigate the potential for assets to be stranded while satisfying the need for utilities to provide timely, safe and reliable utility service at the lowest possible cost and allowing the utilities a reasonable opportunity to recover their prudently incurred costs. And all while managing the potential for rate shock and worsening energy poverty for certain utility customers.

The OEB's direction that the next Enbridge Asset Management Plan address scenarios associated with the risk of under-utilized or stranded assets and propose mitigating measures seeks to reduce the potential cost of stranded gas assets. The OEB considered stranded asset risks related to climate policy in the 2023–24 Enbridge Gas rate case (EB-2022-0200).[30] The OEB determined that the energy transition poses a stranded asset risk related to assets serving both new and existing customers and that the Enbridge Asset Management Plan did not adequately address these risks. The Board directed that the next Enbridge Asset Management Plan address scenarios associated with the risk of under-utilized or stranded assets and propose mitigating measures. The nature of Enbridge's mitigating measures and the OEB's response to those measures will set the stage for further treatment of stranded asset costs related to climate policy and the energy transition in Ontario. This signals a shift in the approach to the regulatory management of stranded asset risks occasioned by climate policy.

Other regulators are requiring utilities to provide Asset Management Plans and Integrated Resource Plans that account for declining gas demand due to electrification. Washington State's Utilities and Transportation Commission ("UTC") is requiring utilities serving both gas and electric customers to file Integrated System Plans that include energy transition planning by 2027.[31] In 2023, the Washington Legislature passed ESHB 1589 (*Large Combination Utilities Decarbonization Act*) requiring UTC to develop rules to allow utilities providing both gas and electric service to merge their resource planning into a single Integrated System Plan. The plans are intended to restrain the utilities from expanding gas infrastructure that may become obsolete to the extent possible by better aligning infrastructure investments with the effects of climate laws. The plans encourage investment in non-pipeline alternatives like electrification programs, demand response, and adequate alignment of accelerated depreciation.

In New York State, utilities are required to file proposed long-term plans every three years. The filings must include at least one scenario with no new traditional gas infrastructure, and the filings must quantify greenhouse gas emissions. The New York Public Service Commission has engaged in gas planning proceedings requiring utilities to demonstrate least-cost, non-pipeline alternatives before approving the expansion of gas networks. The proceedings also consider asset life revisions, targeted retirements and the resulting acceleration of depreciation.[32]

It is becoming increasingly incumbent on utilities with assets that potentially face obsolescence or early retirement to comply with

[30] Ontario Energy Board, *Enbridge Gas Inc — Application to Change its Natural Gas Rates and Other Charges Beginning January 1, 2024*, Decision on Settlement Proposal, EB-2022-0200.

[31] Washington Utilities and Transportation Commission, *State Regulators Adopt Rules for Integrated System Plans*, Docket U-240281 (26 September 2025), online: WUTC <publicnow.com/view/A9CA8167E4A875654138C0752D4966C10B997728?1758930484>.

[32] New York State Department of Public Service, *PSC Accepts Plan to Advance Gas System Reliability* (18 September 2025), online: NY DPS <publicnow.com/view/D0B5B3EF399A45232225C6465D25F44A42F92B4C>.

climate policies to seek approval for accelerated depreciation for any assets at risk (pipelines, meters, and infrastructure). Shortening the lifespan of gas infrastructure, so costs are recovered sooner while customers are still using the system, avoids leaving large unrecovered balances when demand drops. To reduce long-run stranded asset exposure, the Colorado Public Utilities Commission ("CPUC") is requiring Public Service Company of Colorado ("PSCC") to revise its depreciation rates for gas assets and to begin pre-funding future gas system retirements.[33] The CPUC ordered PSCC to establish a trust account to fund future decommissioning costs for gas assets and to contribute $15M annually to the trust.[34] These measures are intended to align with heating sector decarbonization objectives.

Accelerated depreciation for assets at risk to avoid or reduce stranded asset costs results in accelerated cost recovery, increasing annual revenue requirements and ultimately customer rates. This has two obvious consequences. As rates increase for natural gas customers, electrification (e.g. the adoption of heat pumps for home heating, replacement of gas stoves) may become more economically attractive. This result is advantageous for the parallel objective to achieve decarbonization targets. However, as rates increase, low income customers may be adversely and disproportionately affected, worsening energy poverty in the absence of countervailing initiatives. Some of the countervailing initiatives adopted by regulators are discussed below.

Some jurisdictions are taking a more overarching approach by considering performance-based regulation ("PBR") to incentivize utilities to find efficiencies that will offset the effects of the additional costs associated with climate, among other influences on burgeoning utility costs, while mitigating rate increases through caps and rate setting formulas. Transitioning from single-year cost-of-service regulation to multi-year frameworks with metrics for efficiency and affordability can blunt the effect of climate-related utility costs on customer rates. Although only two jurisdictions in Canada (Alberta and Ontario) have adopted PBR, regulators in the US are increasingly adopting or actively considering multiyear frameworks with metrics for efficiency, affordability, and decarbonization. Massachusetts, New Hampshire, Connecticut and Hawaii all have PBR plans, and Oregon has announced that it will adopt PBR. Other states are also considering PBR or other incentive measures. Washington State, North Carolina, New York, Nevada, Colorado, New Mexico, Ohio, Minnesota, Michigan, Pennsylvania, Maryland, Virginia, and the District of Columbia have initiated stakeholder engagements to consider the adoption of PBR and the form it may take. Only two states have not considered adopting some form of incentive regulation, Texas and Oklahoma.

Calculating the costs of stranded assets

The appropriate calculation of stranded asset costs is not always easily determined, and the calculation has consequences for both utility shareholders and customers. Determining the costs of stranded assets when they are considered underused, outdated, unprofitable, or cannot be recovered begins by looking at the asset's remaining net book value. The net book value refers to the portion of the original asset investment that has not yet been recovered in utility rates through depreciation or amortization. If a stranded asset retains any fair market value, that value should be subtracted from the asset's net book value in the stranded asset cost calculation. The fair market value of an asset can be determined by its net salvage value or its resale value in the market. Negative net salvage values that increase stranded asset costs are also possible.

For instance, when coal-fired power generation is phased out, some plants may be suitable for conversion to gas-fired electricity generation. Under these conditions, the fair market value of the phased-out coal-fired plant before conversion should be subtracted from its remaining net book value to determine the stranded asset costs. After conversion, only the arm's length fair market value of the closed plant

[33] Colorado Department of Regulatory Agencies, Proceeding No 25A-0165G.

[34] "UCA Staff Flag Stranded-Asset Risk in PSCo Depreciation and Gas Infrastructure Filings" (13 July 2025), online: *Citizen Portal* <citizenportal.ai/articles/6173324/UCA-staff-flag-stranded-asset-risk-in-PSCo-depreciation-and-gas-infrastructure-filings>.

plus any conversion costs should be included in the capital cost of the gas-fired conversion and allowed in rate base.[35] The stranded costs of the coal plant (net of the fair market value) are excluded from the capital cost of the converted gas fired plant and recovered separately through other mechanisms (e.g. securitization).

Some regulators require utilities to show they have mitigated stranded asset costs before allowing full cost recovery. Some of the statutory requirements in the US related to the recovery of stranded asset costs include a provision that utilities must demonstrate efforts have been made to mitigate stranded costs. Where there is inadequate evidence of mitigation measures, the full amount of the stranded asset costs may not be approved for recovery, given that the utility can be considered imprudent in managing its stranded asset costs. For example, New York and Pennsylvania require utilities to prove mitigation efforts as a pre-condition of full recovery.

Accounting for stranded asset costs in utility rates

Measures to reduce the severity of stranded asset costs resulting from climate initiatives by accounting for potential stranded asset costs in advance will almost certainly result in higher customer rates. When assets are then stranded, the regulator will again be faced with mitigating the effect on customer rates. Regulators are generally loath to increase rates, but when rate increases are necessary, they are then faced with the question of how to equitably share the additional cost recovery among customer classes, particularly when low income customers may be adversely affected.

There is a maxim in rate setting that the individual who causes a cost should bear that cost in their rates. A corollary to that maxim is that the individual who benefits should bear the related costs. However, costs and benefits arising from measures adopted to adhere to climate policies are not easily assigned to any one rate class. Theoretically, everyone in society benefits from climate policies and the associated costs should be borne widely. The additional costs arising from climate policy are the responsibility of the government that institutes the policies and arguably government should defray the costs through tax credits, direct investment, or other measures. However, governments generally leave it to regulators to manage the utility cost consequences of climate policy. Consequently, regulators are faced with the challenge of equitably sharing the costs among rate classes based on considerations such as relative effect or ability to pay.

Equitably sharing the cost of stranding when it occurs

Cost risk sharing between utilities and customers has long been an element of public utility regulation. Traditionally, customers have borne some utility cost risks including fuel cost fluctuations, prudent cost over-runs, load or volume risk (in the absence of revenue decoupling), among others. The challenge for regulators when considering how best to equitably share stranded asset costs is to do so while avoiding appeals on the grounds that any sharing is confiscatory and contrary to the utilities' entitlement to a reasonable opportunity to recover their prudently incurred costs, as demonstrated in the Alberta case. Regulators, the courts, and legislators are wrestling with finding the appropriate cost sharing balance.

In Washington State, the *Climate Commitment Act*[36] is designed to lower greenhouse gas emissions in Washington State by setting a limit on emissions over time. Under the legislation, utilities must either cut their emissions or buy offsets. The Washington Utilities and Transportation Commission ("UTC") has ordered risk-sharing for *Climate Commitment Act* compliance costs which requires the utilities to absorb some of the stranded cost risk, rather than passing all of it on to customers.[37] In its order, the UTC found that it has the authority to impose a risk sharing mechanism on Puget Sound Energy specifically, and determined that the risk sharing mechanism will be addressed in a future rulemaking proceeding that will apply to all utilities it regulates. Interestingly, the Washington State legislation contemplates utilities that provide both gas and electricity service combining their gas and electricity rate

[35] This assumes a vertically integrated utility without deregulated (competitive) generation.

[36] *Climate Commitment Act*, Wash Rev Code § 70A.65 (2021).

[37] Washington Utilities and Transportation Commission, Final Order, Docket U-230968 (21 February 2025).

bases into a single rate base to better manage sharing of decarbonization costs.[38] Thus far, the UTC has not adopted this measure, nor have the utilities requested it.

Mitigating the effect of stranded asset costs on utility rates

Regulators are mitigating the effect of stranded asset costs on customers by adjusting revenue to cost ratios across rate classes, expanding discounts for low-income customers, and implementing billing caps for the remaining gas customers most exposed to stranded cost recovery. In addition to these more targeted approaches, securitization has become a widespread tool to reduce the recovery cost of stranded assets and smooth potential customer rate impacts.

Securitization has emerged as a useful approach to provide for both financial efficiency and customer protection. Securitization replaces the utility's market-based current weighted average cost of capital with lower-cost bond financing to fund the recovery of stranded asset costs over time. Bond financing is treated as a regulatory asset, with its expenses recovered from customers through their rates. Securitization is often used to recover costs associated with stranded assets when facilities are retired early due to climate or other policy and/or regulatory requirements, such as the early closure of coal-fired or nuclear plants. Currently, more than twenty-five states in the US have passed securitization legislation to manage the financial risks of the clean energy transition.

THE FUTURE OF STRANDED ASSET COSTS

Clearly there are regulatory alternatives that offer solutions to the problems of equitable treatment of stranded asset costs. To the extent that utility shareholders or their customers bear the brunt of climate-related utility costs, and in particular the costs of stranded assets that may result, regulators who are charged with the public interest task of finding an equitable sharing of the costs and benefits of climate policies should be given broad legislative authority to consider creative regulatory alternatives. Adopting specific and workable alternatives for the treatment of assets potentially stranded by climate events, climate policies, and the energy transition in general will require regulators to have the legislative authority, latitude, and determination to do so.

Legislation also needs to recognize that climate policies are intended to achieve a universal public good. Responding to climate change benefits everyone and the burden of paying for the implementation of climate policies should not be disproportionately borne by either utility shareholders or their customers. In the emerging utility market, where electricity consumers are increasingly no longer reliant only on utility delivered energy, those who are not reliant on utility delivered energy should not be absolved from supporting the cost of climate initiatives. To do so exacerbates the problem of cost recovery from a shrinking customer base. This may require a broader approach to managing the costs of climate policy through non-regulatory measures such as tax credits or direct government subsidies to defray the risks and potential costs of policy implementation. Alternatively, significant rate restructuring to better align the recovery of utility costs, including climate-related costs, may be required.[39] ■

[38] Amanda Zhou, "State's New Law Involving PSE Aspires to Set a Course for the Future", *The Seattle Times* (22 April 2024), online: <seattletimes.com/seattle-news/climate-lab/states-new-law-involving-pse-aspires-to-set-a-course-for-the-future>.

[39] *See* Mark Kolesar, "Repricing the Grid: Should It Be Regulated as a Common Carrier?" (2025) 13:2 Energy Regulation Q.

THE IMPLICATIONS OF PRICE STABILITY UNDER THE RATE OF LAST RESORT REGULATION FOR LOW-INCOME CONSUMERS IN ALBERTA

*Chloe Haley**[1]

1. INTRODUCTION

The Rate of Last Resort ("RoLR"), is Alberta's current default electricity rate, meaning it is available to all small retail electricity consumers who cannot or will not sign a contract with a competitive retailer.[2] RoLR rates offered by regulated providers are fixed for two-year terms, and they can be adjusted within a 20 per cent bandwidth upon renewal.[3] The establishment of the Rate of Last Resort Regulation appears to have been intended to correct the price volatility experienced under the province's previous default rate, the Regulated Rate Option, which fluctuated monthly to reflect relevant forward market prices.[4] With many competitive retailers offering various fixed-rate and variable-rate contracts, the Rate of Last Resort provides price stability to individuals for whom competitive fixed-rate contracts are unavailable.

Low-income households are those who are the most vulnerable to variable electricity rates. These consumers tend to spend a relatively large proportion of their income on energy,[5] meaning they risk falling behind on their electricity payments if their bills turn out to be higher than expected. Yet, since low-income customers tend to have low credit scores, they are often ineligible for fixed-rate contracts offered by competitive retailers.[6] As such, the only competitive rates available to these consumers are those offered through variable-rate contracts, implying many

* I appreciate the guidance of Dr. Aidan Hollis in developing this paper but note that any remaining errors are my own. I acknowledge the financial support of the Dr. Albert Herman Award in Economics.

[1] Disclaimer: the author of this article is currently employed with the Alberta Utilities Commission as a summer student. However, this paper was completed in its entirety prior to the start of that employment, and the views and opinions expressed herein are solely those of the author and do not reflect the official policy or position of the Alberta Utilities Commission.

[2] Alberta Utilities Commission, "History of the Electricity Industry" (last visited 4 January 2026), online: <auc.ab.ca/history-electric-industry>.

[3] *Rate of Last Resort Regulation*, Alta Reg 262/2005, s 11(4).

[4] Market Surveillance Administrator (Alberta), *Alberta Retail Markets for Electricity and Natural Gas: A Description of Basic Structural Features* (17 July 2014).

[5] KP Green et al, *Energy Costs and Canadian Households: How Much Are We Spending?* (Vancouver: Fraser Institute, 2016) at 18–19.

[6] J McIlroy & B Agar, Affordable Home Energy for All: How Alberta Can Help Its Most Vulnerable Households Escape Energy Poverty (Calgary: Pembina Institute, 2025) at 5.

low-income consumers may elect the RoLR to avoid price uncertainty. Indeed, since 80 per cent of residential consumers were on competitive contracts as of the end of 2025,[7] it seems as though nearly all eligible contract consumers have made the switch off of the default rate.

However, the stability of the RoLR eliminates price risk for small retail consumers only. Since regulated providers must purchase generation to serve their customers, they are exposed to the price variability inherent in Alberta's competitive electricity market. Moreover, since the Rate of Last Resort is available to all residential consumers, regulated providers cannot discourage customers from using the RoLR when their costs of electricity increase. Considering that the rates offered by competitive retailers incorporate prevailing pool prices,[8] consumers who are eligible for contracts tend to search for alternative rates and providers when market prices rise suddenly.[9] Therefore, there is a strong incentive for high-income consumers to switch to the RoLR when pool prices rise, as the RoLR cannot adjust when market prices move. The ability to switch by consumers on contracts is enabled by the fact that cancelling a competitive contract prior to the end of its term is typically inexpensive.[10] As such, RoLR providers must account for the risk that consumers coming to the end of their fixed-rate contract or on a variable-rate contract may switch over to the RoLR if pool prices spike. The only way to control this risk is for RoLR providers to set a relatively high price.

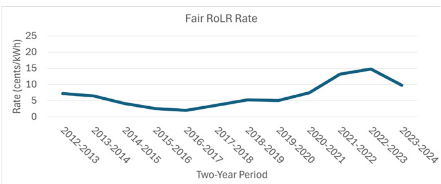
This paper considers whether the risk of migration by high-income consumers to the RoLR corresponds to low-income consumers paying higher RoLR rates than should be necessary? To answer this question, I developed a model to illustrate the differences in RoLR rates when (1) only non-contract consumers are permitted to use the RoLR (termed the 'fair' scenario), and (2) when switching to the RoLR by contract consumers is allowed (termed the 'break even' scenario). Details of the model are presented in the appendix. The model shows that when expected volatility of electricity prices increases, RoLR providers are forced to increase the RoLR price substantially in order to avoid switching into the RoLR. The validity of this model is then supported by a comparative analysis of constructed fair and break-even RoLR rates for each two-year period from 2012 to 2024, with factors heightening the risk of switching listed thereafter.

2. COMPARATIVE ANALYSIS OF CONSTRUCTED ROLR RATES

In this section, I compare fair RoLR rates in the absence of consumer switching to the rates which would allow RoLR providers to break even when switching to the RoLR could occur. Since future prices are unknown, I illustrate how the fair and break-even RoLR prices would have compared for each two-year period between 2012 and 2024 using historical data on pool prices[11] and on the proportion of consumers on competitive contracts.[12] Obviously, the break-even rates constructed for the purposes of this analysis were not observed since the RoLR regulation did not come into effect until the beginning of 2025.

i. Fair RoLR Rates

Figure 1 plots the rates which would allow RoLR providers to just break even when only non-contract customers utilize the RoLR.



[7] Market Surveillance Administrator (Alberta), "Retail Statistics" (last visited 9 April 2026), online: <albertamsa.ca/documents/retail-and-rate-cap/retail-statistics>.

[8] Kristjana Kellgren, interview by Chloe Haley (20 February 2025) [unpublished, conducted via Microsoft Teams].

[9] Yiang Guo, Derek EH Olmstead & Andrew H Wilkins, "What Drives Consumers to Switch Retailers? Evidence from the Alberta Electricity Market" (2025) 206 Energy Pol'y 114770 at 1, 2, 9.

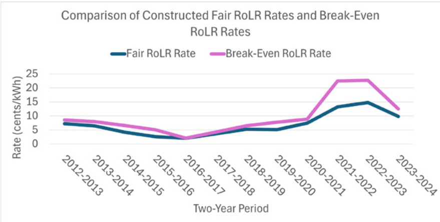
[10] Utilities Consumer Advocate, "Cost Comparison Tool" (last visited 4 January 2026), online: <ucahelps.alberta.ca/cost-comparison-tool/%E2%80%BA>.

[11] Alberta Electric System Operator, "Daily Average Price" (last visited 11 September 2025), online: <ets.aeso.ca>.

[12] *Supra* note 7.

ii. Comparing the Fair RoLR Rates to the Break-Even RoLR Rates

In Figure 2, the fair RoLR rates are plotted against the rates which would let regulated providers break even when a proportion of contract consumers switch to the RoLR in the month with the highest average pool price.



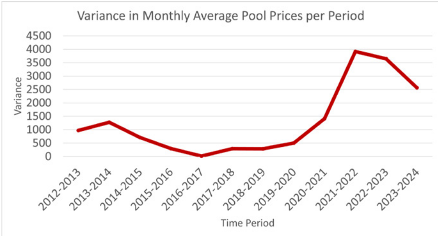
Evidently, the rates necessary to recover RoLR-related costs when consumer switching is permitted are higher than the rates which would prevail if the RoLR were only utilized by a stable group of consumers. As the RoLR cannot be changed to account for minor or infrequent pool price changes,[13] break-even RoLR rates must account for sizeable influxes of customers when pool prices increase. Indeed, this comparison illustrates that non-contract consumers subsidize the ability of contract consumers to migrate to the RoLR by paying higher-than-necessary rates in return for price certainty.

iii. Factors which Impact the Markup on Break-Even RoLR Rates Relative to Fair RoLR Rates

It is clear from Figure 2 that the differences between fair and break-even RoLR rates are not uniform across time periods. There are some periods where fair and break-even rates are almost indistinguishable, while in others the break-even rates are several cents/kWh higher than their fair-rate counterparts. The magnitude of the differences between fair and break-even RoLR rates can be explained by (1) the variability in monthly average pool prices and (2) the proportion of contract consumers during the month of switching.

Variance in Monthly Average Pool Prices from 2012 to 2024

Figure 3 shows the variance in monthly average pool prices in each two-year term from 2012 to 2024. Years with greater pool price volatility see higher variances in monthly average pool prices.



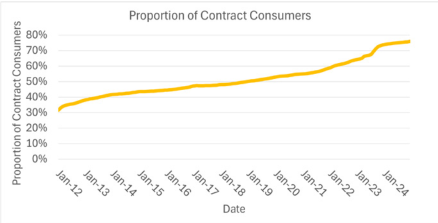
The trend in the variance of monthly average pool prices mimics the fluctuations in the differences between break-even and fair RoLR rates. Indeed, recall that, in the previous figure, the gap between break-even and fair RoLR rates began to close leading up to the 2016-2017 period, with these rates being almost identical as monthly average pool price variance reached its minimum. Yet, as monthly average pool prices began to vary more, the gap between these rates started to reopen, with the largest discrepancy being in the 2021-2022 period. Incidentally, this period experienced the highest variance in monthly average pool prices relative to the other periods under consideration.

These results indicate that larger variances in monthly average pool prices correspond to notable increases in break-even RoLR rates relative to fair RoLR rates. This makes sense intuitively; the larger the variance in monthly average pool prices, the larger the difference between the average pool price in the month of switching and the average pool prices in the months prior, corresponding to a greater volume of contract consumers that will be incentivized to switch to the RoLR. Additionally, greater variability in monthly average pool prices implies shorter durations of sustained price spikes, meaning the increase in expected average costs incurred by providers in the break-even scenario will be more sudden and severe relative to years with lower variances.

[13] *Supra* note 3 at s 11(3).

Proportion of Contract Consumers from 2012 to 2024

Figure 4 shows the proportion of residential consumers on competitive fixed-rate and variable-rate electricity contracts for each month spanning 2012 to 2024.



Clearly, there has been a steady increase in the proportion of consumers on contracts from January 2012 to December 2024. This is important, since the risk of switching becomes more tangible when there is a larger proportion of consumers on contracts. The extent of consumer switching, however, depends on the barriers individuals face when they attempt to cancel a contract. Though all contracts have a mandatory 10-day cooling off period, where consumers can cancel contracts immediately without financial penalty,[14] cancellations made after this period typically require 10 to 90 days' notice, with some retailers charging early exit fees as penalties.[15] These frictions insulate RoLR providers from extensive switching when pool prices rise substantially, since consumers with more scrutinizing cancellation policies have less to gain from moving to the RoLR. Yet, these cancellation policies do not disincentivize switching to the RoLR entirely; consumers with lenient contracts incur relatively low switching costs, meaning migration to the RoLR is quite easy. So, while the risk of switching, and thus burden on non-contract consumers, would be higher in the absence of exit fees and required cancellation notices, switching is still advantageous for some contract consumers. Coupled with the fact that more contract consumers entail more contract expirations in months with high pool prices, RoLR providers face greater price risk when many consumers are on fixed-rate and variable-rate competitive plans.

3. CONCLUSION

The introduction of the Rate of Last Resort Regulation in January 2025 provided a two-year fixed default electricity rate to small retail electricity consumers in Alberta. In contrast to its variable-rate predecessor, the Regulated Rate Option, the RoLR ensures a stable price for consumers, which may be particularly important for low-income households. However, because the RoLR price is fixed in advance for 2 years at a time, the RoLR is a valuable option to contract consumers, who can switch to it if pool prices increase. Contract consumers do not pay for this option: it is non-contract consumers who bear the implicit option premium, through elevated prices on the RoLR.

Since non-contract consumers tend to be relatively low-income, lacking secure employment that would enable them to obtain lower-priced contracts for their household electricity,[16] the implication of the analysis in this paper is that low-income households in Alberta are subsidizing the electricity consumption of wealthier consumers in the province, by paying above their own costs of electricity, by subscribing to the RoLR. While the size of the subsidy depends on the willingness and ability of other consumers to switch over to the RoLR opportunistically, as well as the volatility of pool prices, the analysis using 2012-2024 data suggests that the excess costs may be quite substantial, with non-contract consumers typically paying at least 10 per cent above the fair price, and sometimes much more. The cost of price stability, given the design of the RoLR, is a substantial transfer from the poorest households in the province to those with greater financial capability.

This suggests that the RoLR should be modified. For example, shortening the RoLR to a one-year fixed price would substantially

[14] *Consumer Protection Act*, RSA 2000, c C-26.3, s 27.

[15] Utilities Consumer Advocate, "How to Switch Energy Retailers" (last visited 9 April 2026), online: <ucahelps.alberta.ca/residential/electricity/how-to-switch-energy-retailers>.

[16] Cindy Tran, "'Rate of Last Resort' Will Make Alberta Electricity Rates Less Volatile but More Expensive in the Long-Haul, Experts Say", *Edmonton Journal* (19 January 2025), online: <edmontonjournal.com/news/local-news/rate-of-last-resort-will-make-alberta-electricity-rates-less-volatile-but-more-expensive-in-the-long-haul-experts-say>.

reduce the need for providers to charge above costs. Alternatively, the RoLR could be set on a rolling two-year period to incorporate changes in current and forecasted pool prices, giving contract consumers less of an incentive to switch when the cost of energy rises. Even allowing the RoLR to adjust every so often to account for changes in market conditions, like what is seen with Maryland's default electricity rate[17], would significantly relieve the pressure consumer migration places on RoLR providers' expected average costs.

APPENDIX 1: THE MATHEMATICAL FORMULATION OF THE MODEL

Model Assumptions

For the purposes of this analysis, I have assumed that the sole costs RoLR providers incur arise from the procurement of generation through Alberta's power pool. Any costs associated with transmission, distribution, and billing are excluded from the model, as these costs are not included in the energy charges faced by consumers.[18] While RoLR providers may also purchase some or all of their generation through forward contracts, there is no specific method of generation procurement required under the Rate of Last Resort Regulation.[19] Additionally, since the rates offered through competitive contracts are based largely on pool prices (as acknowledged previously), the risk of switching by contract consumers does not arise from fluctuating forward prices. This indicates pool prices better reflect the increase in costs experienced by RoLR providers when consumer migration is of concern.

Additionally, in the break-even scenario, I have assumed that contract consumers only switch to the RoLR in the month with the highest average pool price, where the willingness to switch follows a uniform distribution based on the savings the RoLR offers relative to that month's average pool price. These assumptions allow the model to account for consumer migration that follows from pool price variability, but they eliminate the noise and potential error that can stem from more granular estimates of consumer switching rates. Furthermore, we would not expect to see additional switching to the RoLR following the month with the highest average pool price, as the savings in these months would not be as substantial as if these consumers had switched earlier.

Derivation of the Fair RoLR Rate

Let α be the proportion of contract consumers in a given two-year period. This implies that the proportion of non-contract consumers in said two-year period is given by $1 - \alpha$. Furthermore, let P_i, $i = 1, 2, \ldots, 24$, be the average pool price in month i.

In the fair scenario, RoLR providers serve $1 - \alpha$ consumers in each month for which their RoLR rates are in place. This implies that, for the duration of a RoLR term, a total of $24(1 - \alpha)$ consumers are served. Since the average price of generation in a month is given by that month's average pool price, the expected average cost associated with the provision of the RoLR is given by

$$E[AC]^F = \sum_{i=1}^{24} \frac{1-\alpha}{24(1-\alpha)} P_i$$

which simplifies to

$$E[AC]^F = \frac{\sum_{i=1}^{24} P_i}{24}$$

So, the RoLR rates necessary for providers to break even in this scenario are given by

$$RoLR^F = \frac{\sum_{i=1}^{24} P_i}{24}$$

[17] Office of People's Counsel, State of Maryland, "Electric SOS Pricing" (last visited 8 April 2026), online: <opc.maryland.gov/Consumer-Learning/Electricity/Utility-Standard-Offer-Service-Rates>.

[18] Utilities Consumer Advocate, "Understanding Your Bill" (last visited 4 January 2026), online: <ucahelps.alberta.ca/residential/electricity/understanding-your-bill>.

[19] *Supra* note 3 at s 11(1).

Derivation of the Break-Even RoLR Rate

Now, when consumer migration is allowed, RoLR providers serve non-contract customers for every month their RoLR rates are in place, and they serve a proportion of contract consumers in months with comparably high average pool prices. Let θ represent the proportion of contract consumers who switch to the RoLR in the month with the highest average pool price. Furthermore, let *m* represent the number of months RoLR providers serve contract customers. This means that, for each of the *m* months, RoLR providers serve θα contract consumers, so *m*θα contract consumers are served in total. The expected average cost associated with providing the RoLR is this circumstance is given by

$$E[AC]^{BE} = \sum_{i=1}^{24} \frac{1-\alpha}{24(1-\alpha)} P_i + \sum_{j \in m} \frac{\theta\alpha}{m\theta\alpha} P_j$$

which simplifies to

$$E[AC]^{BE} = E[AC]^F + \frac{\sum_{j \in m} P_j}{m}$$

or

$$E[AC]^{BE} = E[AC]^F + P^H$$

where P^H gives the average pool price over the months where contract consumers are on the RoLR.

Now, in the break-even scenario, the net revenues RoLR providers receive from serving non-contract consumers are given by

$$NetRevenues^{NC} = (1-a)(RoLR^{BE} - E[AC]^F$$

Likewise, the net revenues RoLR providers receive from serving θα contract consumers are given by

$$NetRevenues^{C} = \theta a\left(RoLR^{BE} - P^H\right)$$

As such, the break-even RoLR rate, *RoLRBE*, occurs when

$$NetRevenues^{NC} + NetRevenues^{C} = 0$$

$$\left(1-a\right)\left(RoLR^{BE} - E[AC]^F + \theta a\left(RoLR^{BE} - P^H\right) = 0$$

which simplifies to

$$RoLR^{BE} = \frac{\left(1-a\right)E[AC]^F + \theta a P^H}{(1-a) + \theta a}$$

To determine when the break-even RoLR rate is greater than the fair RoLR rate, we want to find the conditions for which

$$RoLR^{BE} > RoLR^F$$

We have

$$\frac{\left(1-a\right)E[AC]^F + \theta\alpha P^H}{(1-\alpha) + \theta\alpha} > E[AC]^F$$

$$(1-a)E[AC]^F + \theta\alpha P^H > \left(1-a\right)E[AC]^F + \theta\alpha E[AC]^F$$

$$\theta a P^H > \theta a E[AC]^F$$

$$P^H > E[AC]^F$$

Recall that $E[AC]^F$ is the average of the monthly average pool prices prevailing over the RoLR's 2-year term and P^H is the average of the monthly average pool prices that warrant utilization of the RoLR by contract consumers. Since P^H gives greater weight to high monthly average pool prices, it is apparent that $E[AC]^F$ will never be higher than P^H, meaning the RoLR rates necessary for providers to break even when consumer switching is allowed will always be above the sufficient RoLR rates in the fair scenario.

APPENDIX 2: A NOTE ON THE ESTIMATION OF THETA

The calculation of θ is recursive in nature: its measurement depends on the magnitude of savings the RoLR offers, but the computation of the break-even RoLR rate depends on θ itself. To work around this complication, θ was estimated to be the percentage change in the average pool price from the months prior to contract consumer switching and the month in which consumer switching was to take place. This adaptation ensures θ measures the willingness to switch after contract consumers have faced some significant price change. ■

CASE COMMENTARY: WEST WHITBY LANDOWNERS GROUP INC. V ELEXICON ENERGY INC., 2025 ONCA 821

Reena Goyal, Roy Hrab and Alice Xie[*]

INTRODUCTION

In *West Whitby Landowners Group Inc. v. Elexicon Energy Inc.*,[1] the Ontario Court of Appeal ("**Court**") recently confronted the question of when an intervention by the Ontario Energy Board ("**OEB**") in a cost-sharing dispute constitutes a judicially reviewable decision.

Writing for a unanimous panel, Sossin J.A. allowed the appeal and held that certain letters from an OEB delegated staff member determining the dispute between the parties constituted a binding decision. The Court held the letters comprised legal instruments within the OEB's exclusive jurisdiction affecting the parties' legal rights, thereby giving rise to judicial review.

This decision carries significant implications for how OEB communications, particularly those issued by delegated staff rather than by Commissioners, may be treated by reviewing courts.

BACKGROUND

The appellant, West Whitby Landowners Group Inc. ("**WWLG**"), is a cost-sharing trustee corporation for eleven real estate developers in Whitby, Ontario. The respondent, Elexicon Energy Inc. ("**Elexicon**"), is the licensed monopoly distributor of electricity in the region, operating in accordance with the OEB's Distribution System Code (the "**Distribution Code**") established pursuant to the *Ontario Energy Board Act,* 1998[2] ("**OEB Act**").[3]

WWLG was developing residential subdivisions requiring electricity service. In December 2018, WWLG and Elexicon entered into a Connection Agreement providing that Elexicon would supply electricity through a new municipal substation "MS16" and two new transformers.[4] Under the Distribution Code, new infrastructure like MS16 may be classified as either an "expansion" or an "enhancement" of Elexicon's distribution grid. If MS16 constituted an expansion, WWLG would be required to pay a capital contribution to Elexicon toward its construction costs. If it was an enhancement, Elexicon would bear those costs.[5]

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[1] *West Whitby Landowners Group Inc v Elexicon Energy Inc*, 2025 ONCA 821 [*WWLG*].

[2] *Ontario Energy Board Act*, 1998, SO 1998, c 15, Sched B.

[3] *Supra* note 1 at para 3.

[4] *Ibid* at para 4.

[5] *Ibid* at para 5.

The parties disagreed on the classification of MS16. Their Connection Agreement contained an arbitration provision, referring the question to the OEB and stipulating that such determination would be final and binding. Pursuant to that provision, WWLG wrote to the OEB's Industry Relations office in February 2019 seeking a binding interpretation of the Distribution Code on four points: (1) whether MS16 constituted an expansion or an enhancement; (2) the allocation of capital costs between the parties; (3) whether Elexicon was entitled to charge WWLG $775,000 for future infrastructure relocation; and (4) the appropriate connection horizon.

Notably, WWLG asked the OEB to confirm whether the Industry Relations office could render a determination carrying the same authority as a formal OEB decision and, if not, to refer the matter for a full hearing.[6]

The OEB responded through two staff letters. The first letter was issued in August 2019 by the OEB's Vice President for Consumer Protection and Industry Performance, setting out its "views and conclusions" that Elexicon had properly classified MS16 as an expansion.[7] WWLG objected, elevated the matter to a formal complaint with the OEB and requested a hearing. The second letter was issued by the OEB to the parties in December 2020 reaffirming the expansion classification (but slightly reducing the capital contribution amount). The second letter did not expressly address WWLG's request for a hearing.[8]

WWLG subsequently sought judicial review before the Divisional Court. The Divisional Court held it did not have jurisdiction to hear the judicial review because the OEB had not exercised a statutory power of decision, and WWLG had no standing to compel an OEB hearing.[9] WWLG then pursued an application at the Ontario Superior Court of Justice, asking it to interpret the Distribution Code directly. The Superior Court dismissed the application as an abuse of process, finding the OEB had already resolved the dispute between the parties and that, in any event, the Distribution Code interpretations fell exclusively within the OEB's jurisdiction.[10] WWLG appealed both decisions to the Court, framing the Superior Court appeal as contingent on the Court dismissing the Divisional Court appeal.[11] Since the Court allowed the Divisional Court appeal, it did not address the Superior Court appeal in detail.[12]

The remainder of this commentary is limited to the Court's analysis of the nature of the OEB letters and whether the OEB's intervention amounted to a statutory power of decision.

COURT'S ANALYSIS

The OEB letters constituted a "decision" and not merely an "opinion"

The pivotal question on appeal was how to characterize the OEB's correspondence to the parties. On this point, the Court departed from the Divisional Court's finding that the OEB's letters were merely non-binding "opinions" solicited by private parties.[13]

The Court's decision begins with section 105 of the OEB Act, which grants the OEB broad discretion to receive and resolve complaints concerning potential contraventions of enforceable provisions, and to investigate, mediate, or resolve such complaints as the OEB sees fit.[14] A threshold issue was whether WWLG's February 2019 letter qualified as a "complaint" under section 105 of the OEB Act. The Court found it did for two reasons. First, it was submitted by an affected consumer to the OEB's Industry Relations office, the body responsible for complaints.[15] Second, its

[6] *Ibid* at para 6.

[7] *Ibid* at para 7.

[8] *Ibid* at para 8.

[9] *Ibid* at para 10.

[10] *Ibid* at para 16.

[11] *Ibid* at paras 24–25.

[12] *Ibid* at para 26.

[13] *Ibid* at para 13.

[14] *Ibid* at para 47.

[15] *Ibid* at para 50.

substance challenged Elexicon's classification of MS16 to be inconsistent with the Distribution Code, the interpretation of which is within the OEB's exclusive jurisdiction.[16]

The Court then considered whether the OEB has the statutory authority to decide a dispute through section 105 of the OEB Act. Reading the provision harmoniously with the broader *OEB Act*, the Court treated the text's distinction between "mediating" and "resolving" complaints as deliberate: the former is consensual and non-binding, while the latter encompasses binding determinations.[17] The Court found that sections 19(1) and 19(6) of the OEB Act reinforce this interpretation, vesting the OEB with exclusive authority to determine all questions of fact and law within its jurisdiction.[18]

The Court cited prior case law in support of its interpretation. In *Bennett v Hydro One Inc.*,[19] the OEB's extensive complaint powers were cited as a reason a class action was less preferable. In *Vista Waterloo Hotel Inc. v 1426398 Ontario Inc.*,[20] the court accepted that the OEB's resolution of a complaint fell within its exclusive jurisdiction. Two related decisions prior to the enactment of section 105 of the *OEB Act* also recognized the OEB's discretion over its own complaint process and the permissibility of an OEB decision as a matter of judicial review.[21] On this basis, the Court concluded that section 105 of the OEB Act conferred on the OEB the discretion to accept the referral and resolve the dispute through an interpretation of the Distribution Code over which it has exclusive jurisdiction.[22]

The next issue considered by the Court was whether the OEB reached a final decision or otherwise merely expressed a non-binding opinion. The Court rejected the Divisional Court's characterization of WWLG as having only sought the OEB's "opinion". Rather, the Court found the Connection Agreement's arbitration clause and WWLG's express request for a "final and binding" interpretation made clear the parties were seeking a decision.[23]

Notably, the OEB's own conduct supported the Court's finding. The August 2019 letter set out the OEB staff's "views and conclusions" without disclaiming binding authority.[24] The December 2020 letter subsequently reaffirmed those conclusions, adjusted the capital contribution downward and closed the file without addressing WWLG's request for a hearing. The Court accordingly concluded the December 2020 letter was the OEB's final decision, incorporating the earlier analysis by reference, and that together the two letters constituted "the decision and reasons of the [OEB], interpreting and applying the [Distribution] Code to resolve the complaint."[25]

The letters constituted an exercise of the OEB's statutory power of decision

With the nature of the OEB letters settled, the Court turned to the separate but related question of whether the letters together constituted an exercise of its statutory power of decision making under section 1 of Ontario's *Judicial Review Procedure Act*[26] ("**JRPA**"), thus giving rise to judicial review under subsection 2(1)2 of the JRPA.

Subsection 2(1)2 of the JRPA provides that judicial review is available by way of an action for a declaration or for an injunction, or both, in relation to the exercise, refusal to exercise or proposed or purported exercise of a statutory power. The relevant defined terms are set out in section 1 of the JRPA, defining "statutory power" to include the "exercise of a statutory

[16] *Ibid* at para 51.
[17] *Ibid* at para 54.
[18] *Ibid* at para 56.
[19] *Bennett v Hydro One Inc*, 2017 CanLII 7065 (ONSC).
[20] *Vista Waterloo Hotel Inc v 1426398 Ontario Inc & Ontario Energy Board*, 2021 ONSC 2724.
[21] *Supra* note 1 at para 61.
[22] *Ibid* at para 64.
[23] *Ibid* at para 68.
[24] *Ibid* at para 71.
[25] *Ibid* at para 81.
[26] *Judicial Review Procedure Act*, RSO 1990, c J.1.

power of decision", which is further defined as follows:

> …a power or right conferred by or under a statute to make a decision deciding or prescribing,
>
> > (a) the legal rights, powers, privileges, immunities, duties or liabilities of any person or party, or

The Court's analysis accordingly entailed two elements. First, the decision must flow from a power conferred by statute. Second, it must decide or prescribe the legal rights, powers, privileges, immunities, duties, or liabilities of any person or party.[27]

On the first element, the Court's conclusion followed directly from its earlier statutory interpretation of section 105 of the OEB Act that the OEB's use of section 105 jurisdiction was "by definition, the exercise of a power conferred by statute to make a decision."[28] The Court was unpersuaded by the Divisional Court's reliance on the permissive language of "may" in section 105 of the OEB Act as a basis for concluding the OEB had not exercised a statutory power. While the initial decision to take up the referral was discretionary, once the OEB did its determination attracted the ordinary public law principles of reviewability.[29]

WWLG objected that the OEB's determination was communicated by staff letter, not by Commissioner order. On behalf of the OEB itself, it was argued that the OEB's "primary mandate" to hear and determine questions of fact and law is conferred on panels of Commissioners who act by formal order after a hearing.[30]

The Court was not persuaded by these arguments, noting the exclusive jurisdiction provision in section 19 of the OEB Act speaks of "the Board" not "the Commissioners." Further, the OEB had not argued it lacked the institutional capacity to decide matters through staff analysis or communications.[31] More broadly, the Court emphasized that regulatory bodies routinely issue decisions in forms other than formal orders, and that the vehicle of communication cannot insulate a determination from judicial scrutiny.[32]

The Court drew from the Federal Court of Appeal's analysis in *Telus Communications Inc. v. Federation of Canadian Municipalities*,[33] where the Canadian Radio-television and Telecommunications Commission's language in addressing a dispute was found to be definitive rather than tentative. The Court found the cases to be analogous: the OEB's framing in its December 2020 letter left no room for further reconsideration, signalling an intention to settle the matter conclusively.[34]

On the second element, the Court concluded the OEB's determination affected the parties' legal rights in a concrete way. By interpreting and applying the Distribution Code, the OEB defined what Elexicon was entitled to charge under its licence and, as a result, fixed the financial obligations flowing from the parties' contractual relationship.[35]

With both elements of the statutory definition met, the Court held the OEB letters constituted an exercise of a statutory power of decision under section 1 of the JRPA, and were therefore reviewable under section 2(1)2 of the JRPA. In so doing, the Court wrote in part:

> *"Administrative decision makers, especially regulatory bodies, may issue decisions in many forms. The fact*

[27] *Supra* note 1 at para 92.
[28] *Ibid* at para 96.
[29] *Ibid* at para 100.
[30] *Ibid* at para 101.
[31] *Ibid*.
[32] *Ibid* at para 104.
[33] *Telus Communications Inc v Federation of Canadian Municipalities*, 2023 FCA 79.
[34] *Supra* note 1 at para 106.
[35] *Ibid* at para 113.

> *that a decision may be conveyed in a letter rather than an order is no bar to judicial review…"*[36]

PROSPECTIVE CONSIDERATIONS

Curiously, the Court made its findings without any express consideration of nor reference to the delegation authority under subsection 6(1) of the *OEB Act* which permits the OEB Chief Commissioner to delegate to OEB staff members "any power or duty" with respect to the hearing and determination of matters over which the OEB has jurisdiction.

Indeed, it is this delegation authority that is primarily relied upon for the vast majority of applications brought to the OEB. According to the OEB's most recent adjudicative reporting for the April 1, 2025 to March 31, 2026 fiscal year, 205 of a total of 272 decisions were issued by a delegated authority.[37] Based on the Court's decision, it is reasonable to conclude that subsection 6(1) delegated determinations are subject to possible judicial review similar to determinations made under section 105 of the *OEB Act*. However, the application of the Court's decision to other types of OEB communique is less clear.

On the one hand, the Court expressly distinguishes section 105 determinations from OEB staff "compliance bulletins." It does so on the basis that in the case of staff bulletins the "OEB expressly issues opinions that it intends to be non-binding."[38] This is similar to the OEB's approach to issued letters providing guidance to the industry regarding the implementation of new legal and regulatory requirements:

> *"Similar to Bulletins, these letters are not binding on the OEB; however, regulated entities are expected to follow the guidance and staff will rely on it in assessing applications, addressing complaints and conducting inspections to ensure compliance with the requirements."*[39]

On the other hand, there are instances where OEB staff provide advice and guidance where the binding effect is sometimes unclear. For example, as was initially the case with WWLG and Elexicon, stakeholders submit written enquiries to OEB staff through the Industry Relations office for advice and guidance on various points of interpretation concerning provisions of the *OEB Act* and prescribed regulations, as well as of the OEB's numerous codes, rules and filing requirements.[40]

Responding interpretations from OEB Industry Relations staff are relied upon by stakeholders in, among other things, determining the applicability of mergers, acquisitions, amalgamations and divestitures ("**MAADs**") notice requirements and/or licensing exemptions. These types of OEB staff interpretations can therefore have tangible commercial ramifications arguably affecting parties' "legal rights, powers or liabilities."

Like section 6 decisions, these determinations require an interpretation and application of law which fall within the OEB's exclusive jurisdiction. Like section 105 decisions, these types of OEB determinations may be the result of a complaint or disagreement between negotiating commercial parties as to the correct scope and application of legislative or regulatory provisions to the specific circumstances of a proposed transaction.

If these types of OEB staff communications are binding, then they should be subject to judicial review similar to the findings by the Court in *WWLG*. If they are non-binding, which OEB staff will sometimes expressly state to be the case (i.e., are non-binding on a panel of OEB Commissioners), then it is unclear what the appropriate avenue of recourse is for applicants seeking a second opinion or review. The latter is particularly concerning given the Court's

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[36] *Ibid* at para 104.

[37] Ontario Energy Board, "Adjudicative Reporting Dashboard" (last visited 16 April 2026), online: OEB <oeb.ca/applications/adjudicative-reporting-dashboard>.

[38] *Supra* note 1 at para 109.

[39] Ontario Energy Board, "Staff bulletins and guidance to industry" (last visited 2 April 2026), online: OEB <oeb.ca/regulatory-rules-and-documents/staff-bulletins-and-guidance-industry>.

[40] Ontario Energy Board, "Contact the Ontario Energy Board" (last visited 2 April 2026), online: OEB <oeb.ca/contact-ontario-energy-board>.

obiter supporting the Divisional Court's finding that WWLG did not have the requisite legal standing to compel the OEB to hold a hearing to re-consider the decision on the substantive complaint at issue.[41]

The need for additional clarity on what types of OEB staff communications are binding versus non-binding is even more pertinent in light of recent legislative changes.

The *Protect Ontario by Securing Affordable Energy for Generations Act, 2025* added to the OEB's statutory objectives supporting "economic growth" in relation to the regulation of the electricity sector.[42] The *Protect Ontario by Securing Affordable Energy for Generations Act, 2025* also adds a new section 13.1 to the OEB Act authorizing the OEB Chief Executive Officer to "issue policies to commissions and employees of the [OEB] respecting … timelines for making a determination [delegated] under section 6…[and] information or documents to be considered in…making a determination."[43]

These legislative provisions were subsequently relied upon by the OEB Chief Executive Officer in issuing a public letter on December 16, 2025 stating in part that:

> *"The [Protect Ontario by Securing Affordable Energy for Generations Act, 2025] also empowers the OEB's CEO to issue policies to Commissioners and employees of the OEB with respect to timelines for, and information or documents to be considered in adjudicative proceedings, whether decided by a panel of Commissioners or an employee under delegated authority. I see this as a critical tool to ensure that government policy is considered in deciding applications before the OEB, and that adjudicative matters are dealt with efficiently and effectively".*[44]

Given this affirmation of the OEB's role as a policy taker (rather than a policy maker), what internal OEB procedures or training are in place that may reassure stakeholders that delegated staff decisions, whether expressly made under section 6 or section 105 of the *OEB Act* or otherwise, will be based on a consistent interpretation and application of the new statutory objective to support economic growth in Ontario? How can stakeholders know if and to what extent such OEB staff interpretations may be judicially reviewed?

The OEB may wish to use the Court's decision in *West Whitby Landowners Group Inc. v Elexicon Energy Inc.* as a springboard for initiating a holistic review of how it communicates regulatory directions, including other instances of non-binding tools the OEB uses to provide guidance to and, in some cases, impose requirements on regulated utilities and other stakeholders.

For example, the OEB's *Handbook to Electricity Distributor and Transmitter Consolidations* which is intended "to provide guidance to applicants and stakeholders on applications to the OEB for approval of distributor and transmitter consolidations and subsequent rate applications,"[45] states in part:

> *"This Handbook documents OEB policy. Similar to other policies, OEB panels [of Commissioners] considering individual applications are not bound by the OEB's policy, and where justified by specific circumstances, may choose to apply or not to apply the policy (or to apply a part of the policy)."*[46]

Similarly, the OEB's *Benefit-Cost Analysis Framework for Addressing Electricity System Needs* (the "**BCA Framework**"), which "outlines the methodology electricity distributors are to employ when assessing the economic feasibility

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[41] *Supra* note 1 at paras 120, 125.

[42] *Protect Ontario by Securing Affordable Energy for Generations Act, 2025*, 1st Sess, 44th Parl, Ontario, 2025, Sched 3, s 1.

[43] *Ibid* at Sched 3, s 6.

[44] Letter from Carolyn Calwell, CEO, Ontario Energy Board to Ontario Energy Board Stakeholders (17 December 2025), at 2, online: OEB <oeb.ca/regulatory-rules-and-documents/whats-new-newsletter/whats-new-2025-12-17-1%5C>.

[45] Ontario Energy Board, *Handbook to Electricity Distributor and Transmitter Consolidations* (11 July 2024), at 3, online (pdf): OEB <oeb.ca/sites/default/files/2024-maads-handbook-20240711.pdf>.

[46] *Ibid* at 5.

of using distributed energy resources (DERs) as non-wires solutions (NWS) to address defined electricity system needs,"[47] including mandatory requirements for electricity distributors, provides in part:

> *"The OEB will take account of the BCA Framework in its review of rate applications. However, the BCA Framework is not binding on the OEB's determination, which will also consider the particular circumstances of an electricity distributor's application."*[48]

Do these types of provisions provide the necessary level of regulatory certainty and understanding that "recognizes the importance of consistency and predictability of process for both policy and adjudicative matters, while also recognizing that substantive regulatory outcomes will depend on the specific facts and circumstances which emerge in adjudication or through policy processes"?[49] Are there better ways that guidance and direction can be provided to regulated entities and other stakeholders that minimizes ambiguity while still maintaining the discretionary authority and active adjudicative approach of OEB Commissioners? Arguably, the better approach is for the OEB to provide such guidance to industry participants, rather than be driven by participants' foresight and deliberation to expressly include the OEB as an arbiter of potential future disputes, as was the case in *WWLG*.

CONCLUSION

The effectiveness of a regulator is in no small part a function of its ability to issue clear and consistent guidance and decisions to the entities it regulates, as well as sector stakeholders, to ensure that all parties have a shared understanding of the regulatory framework. This requires the regulator itself (e.g., across staff, adjudicators, and other decision-makers) to have a consistent shared interpretation and understanding of regulatory policies and requirements. Such an environment is needed to ensure that when the regulator communicates, whether by staff through correspondence or by adjudicators through formal adjudicative decisions, the ensuing regulatory interpretations are aligned and not working at cross purposes. With this outcome in mind, further clarity from the OEB on the issues examined in this commentary would be welcomed, particularly given the current rapidly evolving nature of energy policy and regulation in Ontario. ■

[47] Ontario Energy Board, *Benefit-Cost Analysis Framework for Addressing Electricity System Needs* (16 May 2024), at 3, online (pdf): OEB <oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2024-05/OEB_BCA_Framework_FINAL-AODA.pdf>.

[48] *Ibid* at 8.

[49] Ontario Energy Board, *Top Quartile Regulator Report - Phase 1* (31 March 2021), at 20, online (pdf): OEB <oeb.ca/sites/default/files/OEB-top-quartile-regulator-report-20210331.pdf>.

BC UTILITIES COMMISSION APPROVES A SIGNIFICANT INVESTMENT IN NATURAL GAS RESILIENCY

*Matthew Ghikas and Niall Rand**

On October 27, 2025, the British Columbia Utilities Commission ("BCUC") approved[1] FortisBC Energy Inc.'s ("FEI") Tilbury Liquefied Natural Gas Storage Expansion Project ("TLSE Project"), a significant investment in natural gas resiliency. The TLSE Project is a new $1.1 billion Liquefied Natural Gas ("LNG") facility located in a Vancouver suburb, with two-thirds of the tank reserved for emergency supply in the event of a disruption in natural gas supply to the Vancouver Lower Mainland. The regulatory processes culminating in the BCUC's approval of the TLSE Project offer insights into how a Canadian utility regulator has approached the issue of natural gas system resiliency in the absence of industry-wide resiliency standards. FEI's success also illuminates a type of resiliency planning and analysis that can support a significant investment in natural gas infrastructure.

The sections that follow address: (1) the TLSE Project and its resiliency rationale; (2) the regulatory decisions and direction that helped to shape FEI's evidence in support of the TLSE Project; and (3) aspects of the FEI's resiliency analysis that demonstrated that the TLSE Project is in the public interest.

THE TLSE PROJECT AND ITS RESILIENCY RATIONALE

In 2020, FEI filed an application for a Certificate of Public Convenience and Necessity ("CPCN") for its TLSE Project. The TLSE Project, as proposed, consisted of replacing a 55 year-old, 0.6 Bcf, peak shaving LNG facility in the City of Delta with a 3.0 Bcf storage tank and 800 MMcf/d of regasification capacity.[2] The new facility would provide five times the amount of LNG storage, and over five times the regasification capacity as the original facility. Peaking gas supply / peak shaving requirements represented only approximately one-third of the proposed tank and regasification capacity. FEI's justification for the remainder of the capacity was system resiliency; two-thirds of the tank (2.0 Bcf) would be set aside as a "resiliency

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[1] *Re FortisBC Energy Inc Application for a Certificate of Public Convenience and Necessity for the Tilbury Liquefied Natural Gas Storage Expansion Project*, Decision and Order No C-6-25 (27 October 2025), British Columbia Utilities Commission, online (pdf): <ordersdecisions.bcuc.com/bcuc/orders/en/522934/1/document.do>.

[2] *Ibid* at 1.

reserve" to be used during a supply emergency.[3] The total estimated project cost is $1.14 billion, with the incremental cost of the resiliency reserve and additional regasification representing approximately 22 per cent of this cost.[4]

The rationale for this resiliency investment was that FEI relies on Westcoast Energy Inc.'s T-South pipeline ("T-South") for the vast majority of its winter supply of natural gas to Metro Vancouver and Vancouver Island.[5] This creates a significant supply risk for FEI. FEI's evidence was that a total interruption of gas flows (no-flow event) on T-South of less than a day in winter months (even assuming average winter temperatures) would inevitably result in FEI losing the ability to serve Lower Mainland customers within hours.[6] Appliances and commercial and industrial equipment throughout this area would cease to function. At least 600,000 residential, commercial and industrial customers would lose gas service for weeks, primarily due to the time required to relight millions of appliances after gas flows resume on T-South.[7]

FEI's exposure to this supply risk posed by its reliance of T-South was demonstrated in October 2018 by a two-day T-South no-flow event. An explosion near Prince George had disrupted flows on one of the two T-South pipes, and the regulator had required Westcoast to shut down its other pipe for two days as a precaution. There had been no FEI customer outages in that instance because the no-flow event occurred before the winter heating season; gas demand on FEI's system was lower, and FEI was able to access sufficient alternative supply to offset the loss of T-South gas. Despite these favourable conditions, FEI was within hours of outages and there would be outages if the same no-flow event were to occur during the winter heating season.[8]

THE ITERATIVE PROCESS THAT CULMINATED IN FEI'S COMPREHENSIVE 2024 RESILIENCY PLAN

There is no formal resiliency planning process or framework in British Columbia for gas utilities, nor are there generic gas resiliency standards. As described below, settling on the nature of FEI's resiliency planning and reporting was an iterative exercise that occurred over multiple regulatory processes. FEI's second iteration of its resiliency planning, the 2024 Resiliency Plan, was a comprehensive review of vulnerabilities and included very detailed analysis.[9] The depth of analysis in FEI's 2024 Resiliency Plan was ultimately key in the BCUC's approval of the TLSE Project.

The October 2018 T-South no-flow event raised the profile of natural gas resiliency significantly. In early 2019, the BCUC directed FEI to report on what steps FEI was taking in response to the T-South no-flow event.[10] Then, in accepting FEI's 2017 Long-Term Gas Resource Plan ("LTGRP"), in response to concerns raised by interveners about the 2018 T-South no-flow event, the BCUC directed FEI to address security of supply concerns in its next LTGRP. The BCUC left it to FEI to determine the

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[3] *Ibid*.

[4] *Ibid* at 27.

[5] *Ibid* at 1.

[6] FortisBC Energy Inc, "FortisBC Energy Inc Application for a Certificate of Public Convenience and Necessity for the Tilbury Liquefied Natural Gas Storage Expansion Project: Supplemental Evidence (Exhibit B-60)" (24 October 2024) at 47, online (pdf): <docs.bcuc.com/documents/proceedings/2024/doc_78972_b-60-fei-supplemental-evidence-public.pdf>.

[7] *Supra* note 1 at 22; *see also ibid*, Figures 3–4, 21–22.

[8] *Supra* note 1 at 3.

[9] FortisBC Energy Inc, "FortisBC Energy Inc Application for a Certificate of Public Convenience and Necessity for the Tilbury Liquefied Natural Gas Storage Expansion Project: 2024 Gas System Resiliency Plan (Exhibit B-61)" (24 October 2024), online (pdf): <docs.bcuc.com/documents/proceedings/2024/doc_78974_b-61-fei-2024gassystemresiliencyplan-redacted-public-web.pdf.>.

[10] Letter from Patrick Wruck, Commission Secretary, British Columbia Utilities Commission, to FortisBC Energy Inc, BC Hydro, and Pacific Northern Gas Ltd (5 February 2019), Letter L-1-19, online (pdf): <ordersdecisions.bcuc.com/bcuc/orders/en/362391/1/document.do>.

content of what would become a Gas System Resiliency Plan.[11]

FEI included the first iteration of its Resiliency Plan as part of its next Resource Plan, filed on May 9, 2022 (2022 LTGRP).[12] Among other potential resiliency investments, FEI's first iteration of its Resiliency Plan (Initial Resiliency Plan) identified the TLSE Project as a potential resiliency measure to mitigate FEI's risk exposure to a winter no-flow event on T-South.[13] The Initial Resiliency Plan was largely a qualitative discussion of the most significant customer outage risks facing FEI and potential projects that could be proposed to mitigate those risks.

FEI filed its CPCN application for the TLSE Project on December 29, 2020,[14] while the 2022 LTGRP proceeding was still underway and before the BCUC had opined on the Initial Resiliency Plan. The TLSE Project CPCN application, like the Initial Resiliency Plan, emphasized (i) a T-South no-flow event had already occurred once, and (ii) the significant customer outage consequences from a winter no-flow event were known based on system modelling. System modelling also demonstrated that FEI's proposed 2.0 Bcf "resiliency reserve" would provide sufficient gas in the Lower Mainland to, at minimum, support winter load for a full three days. FEI characterized the ability to bridge an upstream supply interruption for three days as a Lower Mainland-specific minimum resiliency planning objective.[15]

On March 20, 2024, the BCUC issued its decision on FEI's 2022 Resource Plan, and directed FEI to prepare another iteration of the Resiliency Plan. The BCUC provided more specific direction to FEI about the content of the next iteration.[16] Shortly thereafter, the BCUC adjourned the regulatory proceeding for the TLSE Project CPCN (Adjournment Decision) and invited FEI to provide additional evidence, offering similar guidance as in its decision on FEI's 2022 Resource Plan.[17]

The BCUC's Adjournment Decision identified the following areas of interest, in particular:[18]

- The current and future threats to the resiliency of FEI's system in addition to the 3 day no-flow event identified in the Application supporting the TLSE Project;
- The assets that provide resiliency in FEI's current system, as well as the existing system resiliency gaps, supported by a quantitative risk evaluation, accounting for probability and consequences;
- Analysis of how FEI's planned projects would address or mitigate these resiliency gaps, including consideration of short, medium, and long term options and the associated cost of these options;
- An assessment of the remaining life of the existing Tilbury Base Plant;
- The impact, if any, of the loss of contracted storage on the resiliency of FEI's system;
- The costs and benefits of the TLSE Project relative to other alternatives that

[11] *Re FortisBC Energy Inc 2017 Long Term Gas Resource Plan*, Decision and Order G-39-19 (25 February 2019), British Columbia Utilities Commission, online (pdf): <ordersdecisions.bcuc.com/bcuc/decisions/en/363860/1/document.do>.

[12] FortisBC Energy Inc, "2022 Long Term Gas Resource Plan (Exhibit B-1)" (9 May 2022) at Appendix E, online (pdf): <docs.bcuc.com/documents/proceedings/2022/doc_66503_b-1-fei-2022-longtermgasresourceplan.pdf>.

[13] *Ibid* at 27–28.

[14] FortisBC Energy Inc, "FortisBC Energy Inc Application for a Certificate of Public Convenience and Necessity for the Tilbury Liquefied Natural Gas Storage Expansion Project: Application (Exhibit B-1)" (24 October 2024), online (pdf): <docs.bcuc.com/documents/proceedings/2021/doc_60434_b-1-fei-tilbury-lng-cpcn-application-redacted.pdf>.

[15] *Ibid* ss 3–4, at 19–118.

[16] *Re FortisBC Energy Inc 2022 Long Term Gas Resource Plan*, Decision and Order G-78-24 (20 March 2024), British Columbia Utilities Commission, online (pdf): <docs.bcuc.com/documents/other/2024/doc_76411_g-78-24-fei-2022-long-term-gas-resource-plan-decision.pdf>.

[17] *Re FortisBC Energy Inc Application for a Certificate of Public Convenience and Necessity for the Tilbury Liquefied Natural Gas Storage Expansion Project*, Decision and Order G-62-23 (23 March 2023), British Columbia Utilities Commission, online (pdf): <docs.bcuc.com/documents/other/2023/doc_70693_g-62-23-fei-tilbury-cpcn-decision-adjourn.pdf>.

[18] *Ibid* at i, ii; *Supra* note 1 at 3.

would provide fewer, equivalent or more resiliency benefits to customers; and

- How the future demand for natural gas would impact the risk that the TLSE Project will not remain used and useful over its expected in-service life.

ELEMENTS OF FEI'S 2024 RESILIENCY PLAN THAT SUPPORTED PROJECT APPROVAL

FEI needed to retain external experts to assist with the necessary analysis, and the analysis and writing took a number of months. FEI filed supplemental evidence, including the next iteration of FEI's Resiliency Plan ("2024 Resiliency Plan") on October 24, 2024.[19] The 2024 Resiliency Plan was much more comprehensive and detailed than the Initial Resiliency Plan. FEI's supplemental evidence addressed all of the points raised in the BCUC's Adjournment Decision and the 2022 LTGRP decision.

FEI's 2024 Resiliency Plan included the following notable elements:

- Identification of all single point of failure vulnerabilities on FEI's system and upstream that, based on system modelling, had the potential to result in a material customer outage in winter;

- Definition of a materiality threshold for inclusion in the 2024 Resiliency Plan focused primarily on number of customers affected;

- Measurement of direct customer impacts (i.e., direct consequences) using two metrics: number of customers experiencing an outage, and customer-outage-days (i.e., number of affected customers multiplied by the expected duration of outage);

- Development of a model by a third party to estimate the consequential economic impacts associated with each vulnerability based on area-specific GDP information. Despite the uncertainty in this type of modelling (which FEI and its experts acknowledged during the regulatory process), the model enabled a comparison of vulnerabilities based on the type of load being served rather than simply customer count. The GDP loss analysis suggested that an outage in an urbanized area with industrial and commercial customers, such as in Vancouver and the Lower Mainland, has the potential to cause cascading adverse economic impacts;

- Third-party qualitative evidence of the adverse health effects of exposure to cold during a winter outage;

- Calculation of the probability of failure for each identified system vulnerability, based on the potential sources of failure or hazard(s);

- Calculation of risk (probability multiplied by consequences) for each vulnerability. This calculation was performed for all three consequence metrics (customer outages, customer-outage-days, GDP losses), and over various time horizons;

- Third-party evidence on how to assess risk. A key point in this evidence was that relying solely on probability-adjusted risk calculations can drive poor decision-making in the context of low probability-high consequence events. There is a tendency to underestimate the risk. To overcome this shortcoming, the third-party evidence recommended the risk analysis be supplemented with "scenario-based" analysis, an established approach that focusses on the consequences of an event or system failure. That is, if the consequences are unacceptable, then even a small probability may be intolerable — similar logic underlies why people purchase earthquake or fire insurance.

As noted previously, the BCUC had wanted more evidence that FEI was focussing on the right resiliency investments. The analysis above allowed the BCUC to compare the relative risk presented by vulnerabilities across FEI's system. It demonstrated that FEI was

[19] *Supra* note 9, Exhibit B-61.

proposing to invest to mitigate its largest risks. It also demonstrated that the unmitigated risk associated with a T-South no-flow event was very large, and the unmitigated risk would still be very large under any realistic scenario assumptions. The BCUC stated, for instance:[20]

> Despite the broad ranges of probabilities and consequences presented by FEI in the 2024 Resiliency Plan, its analysis demonstrates that the risk associated with a loss of supply from the T-South pipeline is significantly greater than any other of the identified gas infrastructure vulnerabilities. Further, the magnitude of the risk is significant in and of itself, as illustrated by the potential billions of dollars of GDP losses that could result from a single winter no-flow event. It is clear that any prolonged outage of supply from the T-South pipeline during the winter would put hundreds of thousands of customers at risk of losing service. FEI provided extensive evidence in the initial phase of the proceeding to demonstrate that a loss of service at this scale would take several weeks to restore service.
>
> …
>
> In instances where there appeared to be a considerable degree of uncertainty, such as with the rate of failure of the T-South pipeline due to internal hazards, FEI demonstrated that the outcomes of its analysis were not materially sensitive to changes in the assumed inputs. FEI also provided benchmarks against which to compare its Baseline value of pipeline rate of failure, such as data from PHMSA and TSB. Further, the Panel observes that there are aspects of the 2024 Resiliency Plan that may actually understate the overall level of risk, such as Exponent's exclusion of any impacts arising from cybersecurity breaches or malicious acts.[21]

The risk analysis in the 2024 Resiliency Plan also provided a baseline that allowed FEI to demonstrate the different risk mitigation benefits under each of the project alternatives. This was important in addressing the BCUC's expressed desire for information on the relative risk reduction for the amount of investment. In essence, the analysis showed that a larger facility provided significantly greater protection against an outage than a smaller facility. Given the strong economies of scale when constructing an LNG facility, customers were clearly getting better value from a larger facility. The BCUC stated:

> As for FEI's methodology for assessment of the various Tilbury and non-Tilbury alternatives, the Panel finds the assumptions and criteria to be thorough and reasonable. They support the choice of [the largest facility] as the Preferred Alternative in light of the significant additional gas supply and resiliency benefits and economies of scale associated with that alternative relative to the other Viable Alternatives.[22]

FEI was able to use the analysis in the 2024 Resiliency Plan to show the considerable risk mitigation value customers would receive even under adverse assumptions about the facility's service life. The BCUC had, in the Adjournment Decision, expressed concern about declining load and stranded assets as a result of the energy transition.[23] This evidence supported both the need for the TLSE Project and FEI's proposal to construct the largest facility alternative.

Interveners generally accepted the analysis in the 2024 Resiliency Plan, including the underlying risk posed by a winter T-South no-flow event. All but one of the intervening ratepayer groups accepted the resiliency need and ultimately supported the TLSE Project as proposed. In several cases, interveners changed their views and supported the TLSE Project after seeing FEI's supplemental evidence and the 2024 Resiliency Plan.

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[20] *Supra* note 1 at 22.

[21] *Ibid*.

[22] *Ibid* at 30–31.

[23] *Ibid* at 31.

CONCLUSION

The BCUC's decision in respect of FEI's Initial Resiliency Plan, the Adjournment Decision and its decision granting a CPCN for the TLSE Project all show a recognition of the importance of resiliency in the gas system. The decisions also illustrate the challenges that utilities face, despite that recognition, in justifying a significant investment in natural gas system resiliency at this time in the absence of industry-wide resiliency standards. The iterative process was lengthy, complex and costly. However, it ultimately resulted in a robust resiliency planning framework that will continue to serve FEI for years to come. And most importantly, it culminated with the approval of a very important resiliency project. ■

CAUTION BEFORE CONVERGENCE: REFLECTIONS ON THE OEA'S ONTARIO DSO ROADMAP

Institutional roles, regulatory sequencing, and the economics of DER value

Adam White

ABSTRACT

The Ontario Energy Association's *Ontario DSO Roadmap*[1] ("the Roadmap"), prepared by Capgemini, is a detailed and thoughtful contribution to the ongoing debate over the future role of Distribution System Operators ("DSOs") in Ontario. It sets out a coherent, phased pathway toward a Market Facilitator DSO ("MF-DSO") model, positioning local distribution companies as neutral coordinators of local flexibility markets. The Roadmap is an important sector intervention, and a useful prompt for clarifying how distribution level coordination might evolve in Ontario.

Based on recent work on non-wires solutions and flexibility initiatives, I am not yet convinced that early commitment to a specific DSO market form is warranted. My perspective reflects three related concerns: the risk of blurring longstanding institutional boundaries between energy coordination and network capacity responsibility; the fragile economics of many distributed energy resources ("DER") enabled non-wires portfolios, even when energy system benefits are included; and the challenge of translating promising pilot activity into rate-funded programs that can be sustained through adjudication. In this context, I focus on the Ontario Energy Board's dual role as both policy-setting body and adjudicative tribunal, and on how the pace of decision-making is shaped once proposals move from experimentation to precedent. I conclude by outlining a capability-first path forward that preserves regulatory optionality while allowing practical progress to continue.

1. INTRODUCTION: A SERIOUS CONTRIBUTION — AND WHY IT MERITS CAREFUL REFLECTION

The *Ontario DSO Roadmap*, released early 2026, is a substantial contribution to the debate. It is well-resourced and thoughtfully constructed, reflecting international experience and the practical perspectives of Ontario distribution

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[1] Capgemini Canada, *Ontario DSO Roadmap*, prepared for the Ontario Energy Association (January 2026), online: Ontario Energy Association <energyontario.ca/wp-content/uploads/2026/01/OEA-DSO-Roadmap_-Final.pdf>.

utilities. Its emphasis on readiness, phased implementation, governance, shared services, and workforce capability distinguishes it from earlier, more speculative DSO discussions.

The Roadmap advances a clear preference for a Market Facilitator DSO, positioning local distribution companies as neutral coordinators of DER participation and local flexibility markets in structured interface with the Independent Electricity System Operator ("IESO"). This is coherent and defensible, particularly for larger distributors already grappling with DER integration. It is also a sector-led proposition.

My observations are informed by recent work on non-wires solutions ("NWS") and flexibility initiatives undertaken with distributors, customers, developers, and aggregators, including projects carried out under regulatory innovation frameworks. That experience has highlighted both the promise of stronger distribution-level coordination and the practical constraints that emerge once initiatives transition from pilots to rate-funded programs. I focus here on those constraints, and on how they shape the pace and form of institutional change.

Two concerns motivate my perspective.

The first concern is institutional. Ontario's system has evolved around a functional division: the IESO is responsible for energy system operation and optimization, while distributors are responsible for local reliability, capacity planning, and asset stewardship. A Market Facilitator DSO places distributors closer to dispatch-adjacent, market-facing coordination. Even with safeguards, that can blur accountability — especially under stress conditions — between energy management and capacity provision.

The second concern is economics. Part of the pro-market facilitator narrative assumes DERs will reveal sufficient value, once coordinated, to support durable business cases. Experience to date is more mixed. Distribution-driven NWS cases often have thin margins and high sensitivity to assumptions about growth, timing, and performance. Even when energy system benefits are included, portfolios may depend on stacking value streams whose settlement and governance remain uncertain. Markets can reveal value where it exists, but they do not create it.

These concerns help explain why model neutrality can be a strength at this stage. Neutrality preserves regulatory optionality, emphasizes capabilities over institutional form, and allows evidence to accumulate before commitments are locked in. By contrast, the Roadmap moves from capability development to end-state advocacy — understandable from a sector perspective, but consequential for a regulator acting in the broader public interest.

This discussion is not intended to diminish the value of distributor-led innovation; the focus is on how those ideas translate — or struggle to translate — once they are brought before the Board for approval.

The Roadmap can be read as an important provocation — one that sharpens the questions the regulator must ask — rather than as a blueprint to adopt wholesale. The discipline of phased readiness, shared services, and governance rigor should be retained. But the choice of market form, the allocation of coordination authority, and the institutional treatment of DER value should remain open until the economics and accountability implications are better established.

This article proceeds as follows: the Roadmap is first summarized, then the case for model neutrality is examined, followed by discussion relating to the governance boundary between energy coordination and network responsibility, and the economics of DER-enabled NWS. The article concludes with a capability-first path forward that avoids early lock-in.

2. WHAT THE ROADMAP PROPOSES

The Roadmap is best understood as a sector-led response to a perceived gap between the pace of DER growth and the pace of regulatory and institutional adaptation. It argues that distributors are being asked to make operational and investment decisions using tools and frameworks not designed for a more decentralized system.

2.1. Purpose and orientation

The Roadmap is framed as an input to the Ontario Energy Board's DSO Capabilities[2] consultation and is intended to accelerate decision-making. It argues that pilots and utility-specific initiatives risk fragmentation without a clear target state and mandate, and that model clarity is a prerequisite for efficient sector investment in systems, skills, and processes.

Importantly, the Roadmap does not present itself as neutral. It advances a clear preference for a specific end state and organizes its analysis around what would be required to reach that state in a disciplined, phased manner.

2.2. The preferred end state: A Market Facilitator DSO

At the center of the Roadmap is an explicit endorsement of a Market Facilitator DSO model. Under this model, local distribution companies would act as neutral facilitators of local flexibility, coordinating DER participation at the distribution level and interfacing with the Independent Electricity System Operator to ensure alignment with bulk-system operations. The MFDSO is presented as a way to unlock DER value efficiently while maintaining system reliability and neutrality.

The report emphasizes safeguards — governance structures, neutrality rules, and clear accountability — to manage conflicts of interest and ensure fair access. Nonetheless, the MFDSO is treated as the preferred evolution of distributor responsibilities in a high-DER future, rather than one option among several.

2.3. A three-phase roadmap to implementation

To move from today's environment to the MFDSO end state, the Roadmap proposes a three-phase path, with indicative timelines reflecting early adopters rather than a uniform mandate across all distributors.

- Phase I: Decision and Enablement (2026–2028) affirms the MFDSO model, clarifies roles and neutrality, and begins capability investment.
- Phase II: Building and Scaling (2029–2034) institutionalizes capabilities and scales beyond pilots, tailored to differing utility maturity.
- Phase III: Full Integration (2035+) envisions interoperable platforms, standardized services, and ongoing performance monitoring.

The Roadmap is careful to note that these timelines are indicative and that readiness will vary, but the direction of travel is unambiguous.

2.4. Alignment with the OEB's DSO Capabilities framework

The report maps its recommendations to the four workstreams in the OEB's DSO Capabilities[3] consultation and presents the MFDSO model as a concrete answer to the regulator's own questions.

This framing is part of the Roadmap's core move: to translate an open consultation into a preferred institutional destination.

2.5. Strengths of the Roadmap's approach

Even viewed critically, the Roadmap has notable strengths. It treats DSO development as institutional change, not just technology deployment, and gives sustained attention to workforce capability, cybersecurity, governance, and shared services. It also acknowledges distributor heterogeneity and the potential role of shared or "DSOasaservice" arrangements for smaller utilities.

These strengths help explain the Roadmap's traction: it offers clarity and momentum at a time when many stakeholders are frustrated by uncertainty.

Precisely because the Roadmap is coherent, it warrants careful examination. The sections that follow question whether convergence on a Market Facilitator DSO — and the implied sequencing — is justified by current economics, institutional roles, and empirical experience in Ontario.

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[2] Ontario Energy Board, *Distribution System Operator Capabilities*, online: OEB <engagewithus.oeb.ca/distribution-system-operator-capabilities>.

[3] *Ibid*.

3. WHY MODEL NEUTRALITY IS A DELIBERATE AND NECESSARY DESIGN CHOICE

3.1. Neutrality as regulatory discipline, not indecision

At the center of the Roadmap is the question of model neutrality. The Roadmap advances a clear preference for a Market Facilitator DSO end state.

An argument for neutrality on the ultimate institutional form of the DSO should not be seen as accidental, nor as a failure to take a position. It should be seen as a conscious design choice rooted in regulatory discipline.

There are practical questions to be asked — where flexibility is viable, what functionality is required, and how readiness can be demonstrated within existing OEB processes — before a commitment is needed to any single end-state DSO model.

In practice, neutrality has been less about withholding judgment and more about keeping sequencing manageable. In projects where distributors, customers, and developers are working through real system needs, the immediate questions tend to be practical ones: Is flexibility actually available in the constrained area? What level of visibility and control is required? How would performance be verified if the solution were relied on in planning?

Deferring decisions about market form has allowed that work to proceed without forcing agreement on institutional end states before the evidence is ready. Where coordination approaches prove workable and economic, the case for expanded authority can then be tested in adjudication. Where they do not, the system avoids having locked itself into structures that are difficult to unwind.

3.2. Capabilities first, market form later

Separate the question of what needs to be done from the question of who ultimately does it, and through what market structure. Basic work must happen — needs assessment, customer availability, functional assessment, and economic assessment — before it can be determined whether flexibility is a viable alternative to traditional infrastructure in any given context.

3.3. Preserving regulatory degrees of freedom

From a regulatory perspective, early convergence on a single DSO model carries significant risk. Institutional design choices in electricity systems tend to create path dependency: once market rules are codified, platforms are funded, and organizational roles are formalized, changing direction becomes difficult even if underlying assumptions change. Neutrality in early frameworks helps preserve degrees of freedom at a stage when uncertainty remains high.

This concern is particularly acute in the DSO context because multiple elements are evolving simultaneously: DER technology, economics, customer participation, data availability, coordination with bulk-system markets, and incentive structures. An orientation that is bottom-up and evidence-based, focusing on implementation feasibility rather than top-down policy positioning, supports learning across this uncertain terrain.

Neutrality also allows for differentiation across distributors. Ontario's local distribution companies ("LDCs") vary widely in size, system complexity, and DER penetration. A neutral, capability-focused framework enables some distributors to move quickly on specific use cases while allowing others to proceed more cautiously, without forcing all participants into a single institutional trajectory.

3.4. Avoiding premature institutional lock-in

The practical effect of neutrality is to delay institutional lock-in until the system has demonstrated that it can support it. This does not mean delaying action. On the contrary, regulators should encourage distributors to act — to integrate flexibility into planning, to test non-wires solutions, and to build operational experience — but to do so in a way that generates evidence rather than commitments.

Neutrality functions as a sequencing device: capability before authority, learning before locking in. The risk of drift is real only if neutrality is mistaken for inaction; in practice, structured frameworks can accelerate experimentation by decoupling near-term work from end-state agreement.

4. A CENTRAL GOVERNANCE TENSION: ENERGY COORDINATION VS. CAPACITY AND NETWORK RESPONSIBILITY

4.1. Two coordination problems that are often conflated

At the heart of the DSO debate lies a distinction that is easy to blur in conceptual discussions but difficult to ignore in practice: the difference between energy coordination and capacity (or network adequacy) responsibility. These are related but distinct coordination problems, with different temporal characteristics, economic signals, and institutional implications.

Energy coordination is primarily about balancing and optimization in real and near-real time, producing marginal price signals and managing system-wide constraints — naturally suited to the bulk system.

Capacity and network responsibility is about adequacy over time: whether local infrastructure (or alternatives) can reliably serve load under peak or stressed conditions, and how discrete investments are made, deferred or avoided. These questions are local, planning-driven, and episodic.

The challenge for DSO design is not that these domains interact — they clearly do — but that they require different coordination logics and different accountability structures.

4.2. Ontario's institutional structure and why it matters

Ontario's electricity system has evolved around a relatively clear institutional structure. The IESO is responsible for bulk-system operation, energy market administration, and system-wide reliability. LDCs are responsible for the planning, operation, and maintenance of their networks, including decisions about capacity investments and alternatives to traditional infrastructure.

This division is not arbitrary. It reflects differences in scale, information, and risk. Energy markets benefit from centralized optimization and common price signals; distribution planning benefits from localized knowledge, engineering judgment, and long-term asset stewardship. Importantly, this structure also clarifies accountability: when something goes wrong, it is generally clear which institution is responsible and under what regulatory framework it is held to account.

Any redefinition of DSO roles must therefore be assessed not only in terms of efficiency or innovation potential, but also in terms of how it affects this accountability structure.

4.3. Where the Market Facilitator DSO introduces tension

The Market Facilitator DSO model advanced in the Roadmap moves distributors closer to market-facing coordination roles. Market facilitation, even when carefully circumscribed, entails activities such as accepting offers, sequencing activation, and managing interactions between local resources and broader system needs. These activities sit uncomfortably close to the domain of energy coordination, particularly when local flexibility is also expected to participate in bulk-system markets.

The Roadmap acknowledges neutrality safeguards and interfaces with the IESO. But facilitating a market is not the same as administering a program: it entails sequencing, prioritization, and settlement choices that resemble energy-management decisions, even if framed as local.

The risk is less deliberate overreach than boundary erosion as complexity grows. Under stressed conditions — when local constraints and system-wide shortages coincide — responsibility can become harder to assign.

4.4. Accountability under stress: the real test of institutional design

Institutional arrangements are rarely tested by average conditions; they are tested by extremes. In the DSO context, this raises practical questions that a Market Facilitator model must answer convincingly. When local flexibility is scarce, prices spike, or DERs fail to respond as expected, who is accountable for the outcome? If local activation to address a distribution constraint conflicts with bulk-system dispatch priorities, whose decision prevails, and under what rules?

These questions go to the core of regulatory oversight and dispute resolution. From a regulator's perspective, preserving clear lines of accountability can be as important as improving coordination efficiency.

4.5. Capacity provision is not energy management by another name

A recurring theme in DSO discussions is the assumption that local flexibility can be treated symmetrically with energy resources, simply at a smaller scale. This assumption underpins much enthusiasm for local markets. Yet many capacity-driven use cases do not behave like energy markets. They are activated infrequently, targeted to specific assets, and valued primarily for their option value rather than continuous marginal production.

In such cases, the logic aligns more with procurement and contracting than market clearing. The distributor's task is to ensure dependable capability when needed, not minute-by-minute optimization.

4.6. Why role clarity should precede role expansion

The argument here is not that distributors should never play an expanded coordination role, nor that local markets are inherently inappropriate. It is that role clarity should precede role expansion, particularly when new roles blur longstanding institutional boundaries.

The neutrality embedded in the OEB's default framework reflects an awareness of this risk. By focusing on capabilities rather than end states, distributors can build experience in identifying, procuring, and operating non-wires solutions without assuming that market facilitation is the inevitable destination. This sequencing preserves the ability to assess, with evidence, whether expanded market roles actually improve outcomes or simply redistribute responsibility.

4.7. Implications for regulators

For regulators, the central implication is straightforward: decisions about DSO roles should be evaluated through the lens of institutional coherence and accountability, not solely through the promise of innovation or alignment with international models. The question is not whether local flexibility should be coordinated — it clearly must be — but how that coordination is best achieved.

The sections that follow build on this governance concern by examining whether the economic characteristics of DERs and non-wires solutions support the level of market sophistication implied by a Market Facilitator DSO, and whether shared platforms can deliver many of the same benefits without prematurely reallocating authority.

5. ECONOMIC REALITY CHECK: DERS, NWS, AND THE DIFFICULTY OF A STANDALONE BUSINESS CASE

5.1. Why "distribution cost avoidance" is a hard foundation to build on

Ontario's regulatory architecture for non-wires solutions is designed to force economic clarity. The OEB's Benefit-Cost Analysis ("BCA") Framework[4] requires a mandatory Distribution Service Test ("DST"), with an optional Energy System Test ("EST") for system-wide impacts. In practice, the DST is where most distribution-justified NWS proposals rise or fall, because the central quantified benefit is typically distribution capacity deferral or avoidance.

Distribution deferral value is often location-specific and episodic, becoming material only during certain hours or under certain growth scenarios. As a result, DST results are sensitive to assumptions about load growth, the timing of avoided investments, and portfolio performance during binding hours. Even when avoided costs are real, the value available to pay for dependable flexibility can be modest relative to the actual acquisition and integration costs of the kilowatts.

5.2. "Who ultimately pays" is not a footnote — it is the business case

A recurring feature of distributor-led NWS concepts is that much of the capacity sits behind the meter. Where the NWS capacity is customer-sited, the implication is that the ultimate funder of NWS is the customer itself. This is more than a modelling detail: it highlights the central economic challenge that many DER options require customers to bear

[4] Ontario Energy Board, *Benefit-Cost Analysis Framework for Addressing Electricity System Needs* (16 May 2024), online (pdf): OEB <oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2024-05/OEB_BCA_Framework_FINAL-AODA.pdf>.

upfront capital and operational burdens that are not naturally aligned with the distribution value being pursued.

In addition, the BCA Framework's emphasis on symmetrical treatment affects how "who pays" is reflected in regulatory tests. The BCA Framework notes that host (customer) costs and benefits are excluded from the DST and EST to avoid asymmetry and bias, referencing the Framework's "symmetrical treatment" principle. This approach is analytically disciplined for regulatory comparisons — but it also means that a large portion of the real economic burden of behind-the-meter options can sit outside the formal tests, surfacing instead as the practical requirement for incentive payments large enough to make participation rational.

5.3. Energy system benefits can be large — and that both helps and complicates matters

One response to the thinness of distribution deferral value is to broaden the lens and include energy system impacts. The OEB's framework anticipates this by allowing an optional EST that considers generation and transmission impacts from the Ontario system perspective. In principle, layering energy system benefits onto an NWS portfolio should make the overall economics appear substantially stronger.[5]

Energy system benefits are in fact frequently far larger than distribution deferral value. This matters: DER portfolios may be socially efficient even when the distribution-only case is marginal or negative.

But large system-wide benefits create a mandate problem: who procures, dispatches, and funds value that sits outside the distributor's direct accountability? The EST is optional in distributor filings precisely because many energy system benefits are not within a distributor's control.

5.4. The "value stacking" fragility problem: plausible on paper, uncertain in practice

In practice, many DER portfolios are viable only when value streams are stacked (distribution deferral, reliability, and energy system impacts, potentially alongside other programs). The OEB NWS Guidelines and BCA Framework acknowledge this complexity and set expectations for evidentiary discipline in presenting such cases.

Stacking, however, requires workable arrangements for settlement, verification, and cost responsibility. When value is assembled from multiple components, the investment case can become sensitive to methodological and institutional choices, not just engineering performance.

5.5. The hidden cost driver: treating NWS capability as "incremental"

A further challenge is that the cost of making NWS operable — data, customer acquisition, contracting, monitoring and verification, and operational workflows — can dominate early economics if attributed to a single project. These fixed and organizational costs do not scale linearly with kilowatts procured, so early benefit-cost ratios can look weak even when the underlying concept is sound.

There is not yet a single settled template for what a proportional evidentiary package should look like under the OEB's NWS Guidance[6] and BCA Framework. That flexibility creates room for learning — but it also means early NWS cases will be sensitive to methodological choices about enabling costs, baselines, and performance assumptions.

5.6. Implications for the DSO debate: markets do not manufacture value

The argument is not that DERs lack value. It is that the economic base for many DER-enabled NWS cases is thinner and more conditional than DSO narratives sometimes imply — especially when distribution deferral is

[5] *Ibid*.

[6] Ontario Energy Board, *Non-Wires Solutions Guidelines for Electricity Distributors*, EB-2024-0118 (28 March 2024), online (pdf): OEB <oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2024-03/OEB_2024%20NWS%20Guidelines_20240328.pdf>.

modest and the remainder depends on benefits outside a distributor's mandate. The OEB framework reflects this: the DST is mandatory and distribution-anchored; the EST is optional and system-wide.

If underlying value is localized and episodic, continuous local markets should be treated as a hypothesis to test, not a default. Capability building and interoperability should proceed; market authority should remain proportionate to demonstrated opportunity.

6. MARKET FACILITATION VS. SYSTEM COORDINATION: MARKETS ARE NOT FIRST PRINCIPLES

6.1. Markets can reveal value, but they do not define the problem

The Roadmap's preference for a Market Facilitator DSO implicitly treats "market-making" as the natural endpoint for distribution-level flexibility. A counterweight view begins from the opposite direction: the coordination problem comes first, and the choice of solution — including whether a market is warranted — comes second. In the Ontario context, this distinction is more than semantic. The functionality required for distributors to integrate non-wires solutions is not necessarily analogous to what would be required to "stand up" a full flexibility market; it depends on whether acquisition and activation are program-based or market-based.

This framing distinguishes between a "market" as an economic context and a "marketplace" as a specific platform or venue for transactions. The difference matters because a marketplace is an institutional choice — one with fixed costs, governance implications, and a need for sufficient participation — whereas many distribution service needs can be addressed economically through more direct forms of coordination without requiring continuous price discovery or frequent transactions.

6.2. Distribution service needs often favour targeted coordination over continuous market clearing

Distribution service needs are typically local, constraint-driven, and time-bounded: manage peak loading on a specific element, often to defer a discrete investment. That profile does not automatically imply a standing local market platform. If an NWS can be dispatched against the binding hours, simpler procurement and activation coordination approaches may be sufficient.

Before Ontario commits to an institution whose raison d'être is market facilitation, it should be confident that the predominant near-term coordination problems actually require market infrastructure rather than operational and contractual coordination.

6.3. "Flexibility" frequently includes resources that are not naturally market-procured

A further caution arises from what Ontario policy and guidance already count as "flexibility" or NWS-eligible resources. The OEB's Non-Wires Solutions Guidelines provide examples that include dispatchable resources such as demand response and storage, as well as longer-term components like efficiency or managed load that reduce exposure to peak conditions over time. The IESO's electricity demand-side management ("eDSM") framework[7] targets many of the same customers and technologies, but for system-level resource adequacy objectives — highlighting that similar customer actions may be pursued for different reasons, and that not all resources labelled "flexibility" are intended to be dispatchable or locationally responsive from a distribution system perspective.

This matters because many of these options do not behave like classic market commodities. The variation of customer size and type, and available combinations of technology, creates a diverse supply chain. Intermediate agents (aggregators) can play an important role in customer participation and price formation. Technology manufacturers and metering providers also participate in setting prices for dispatchable control.

Long-term assets such as retrofits for mechanical, thermal, and electrical upgrades can permanently reduce peak demand — high upfront costs followed by ongoing reductions — but might not be

[7] Independent Electricity System Operator, *Electricity Demand Side Management (eDSM) Framework*, online: IESO <ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/Electricity-Demand-Side-Management-Framework>.

procured in a real-time flexibility market. The conclusion is not that markets are irrelevant, but that treating market facilitation as the default end state risks overfitting institutional design to a small subset of dispatchable, short-duration resources, where simpler, more durable, and more cost-effective opportunities may be available over time.

6.4. Program-based and bilateral approaches are not second-best; they are often fit-for-purpose

Ontario's current NWS landscape has been shaped more by programmatic and bilateral approaches than by formal market constructs. Flexibility does not always mean running a local market or auction, and where a need can be met by a few known resources or a long-term demand reduction, a full market platform might be overkill.

This is not an argument against sophistication. It is an argument for sequencing and proportionality: use the simplest mechanism that reliably delivers the required service, while building the capability base that could support more complex arrangements later if and when conditions warrant.

6.5. When do flexibility markets make sense? Competition, not coordination, is the differentiator

A defensible role for local flexibility markets emerges when the underlying conditions support genuine competition and repeated transactions. Flexibility markets are most useful when multiple providers can compete to provide the service at least cost; otherwise, traditional programs or direct contracts may achieve the goal more straightforwardly.

This perspective also helps reconcile the "market" and "marketplace" distinction. A marketplace can be designed to engage customers in a simple, accessible way, and aggregators can help translate customer-sited capabilities into transaction-ready offerings. But these are design opportunities, not proofs of necessity. If the distribution problem is primarily one of local constraint management with episodic dispatch needs and thin distribution deferral value — as discussed in Section 5 — then the bar for standing up new market institutions should be correspondingly high.

6.6. Implication for the DSO debate: capability first, market form later

The near-term priority should be to strengthen coordination capabilities — planning integration, customer targeting, data visibility, operational procedures, and interface management. For many use cases, modest extensions of business-as-usual processes can be enough to identify candidates, procure availability, and dispatch and verify performance when needed.

This is the sense in which markets are not first principles. The first principles are: define the system need, identify feasible alternatives, ensure accountability and operational reliability, and only then choose the institutional mechanism — market, program, bilateral contract, or hybrid — that fits both the economics and the governance context.

7. SHARED PLATFORMS WITHOUT PREMATURE MARKET AUTHORITY

7.1. Where there is broad alignment: platforms, interoperability, and shared services

One of the strongest and least controversial elements of the Roadmap is its emphasis on shared platforms, interoperability, and common services. On this point, there is substantial alignment across the sector. Few would dispute that Ontario's distributors face growing challenges related to DER visibility, data access, telemetry, monitoring and verification, cybersecurity, and settlement-grade record-keeping. These are not hypothetical future needs; they are already constraining the ability of distributors to plan, assess, and operate non-wires solutions under existing regulatory expectations.

Importantly, the case for shared platforms does not depend on the adoption of a specific DSO market model. Common data standards, interoperable systems, and shared service arrangements can support a wide range of coordination approaches, from program-based NWS procurement to bilateral contracts and, eventually, more market-like approaches. In this sense, the Roadmap's platform agenda is best understood as foundational infrastructure, not as an implicit endorsement of market facilitation as the default operating role.

This distinction matters because platform investments are costly, long-lived, and difficult to unwind. Regulators should therefore be attentive to what functions those platforms are enabling, and who is granted authority to use them for price formation, dispatch sequencing, and settlement.

7.2. Platforms are not markets — and data exchange is not price formation

A recurring risk in DSO discourse is the quiet conflation of platforms with markets. Data exchange, visibility, and coordination are often discussed in the same breath as bidding, clearing, and settlement, even though these are conceptually and institutionally distinct activities. The key point is that data-sharing infrastructure can enable multiple coordination approaches; it does not, by itself, require distribution-level price formation or market-clearing authority.

A shared registry, telemetry backbone, and monitoring and verification service can materially improve planning and operational confidence without conferring market authority. Market clearing and local price formation, by contrast, raise governance and accountability questions and require explicit interfaces with bulk-system operations.

Where DER value is thin or capacity-driven, the incremental benefit of continuous price formation may be limited. Platforms that support contracted availability, targeted dispatch, and auditable performance may deliver most benefits with less institutional complexity.

7.3. The danger of coupling platform build-out to a single end state

The Roadmap understandably seeks to provide clarity and direction after years of pilot activity. However, coupling the development of shared platforms too tightly to a single DSO end state risks narrowing regulatory options prematurely. Once platforms are designed around market-clearing logic — specific bidding formats, settlement rules, and dispatch hierarchies — it becomes difficult to repurpose them for alternative coordination models without significant re-engineering.

Heterogeneity amplifies this risk. Larger utilities may justify more complex tools sooner; smaller utilities may not. A platform strategy that assumes universal readiness for market facilitation can impose unnecessary costs. Shared platforms should be treated as modular and role-agnostic and let evidence determine where markets add value.

7.4. A modular architecture: coordination without role confusion

A modular platform architecture allows Ontario to separate three questions that are often collapsed into one:

1. What information and control capabilities are required? (e.g., DER registration, visibility, telemetry, monitoring and verification, cybersecurity)

2. How customer and technology portfolios are constructed and managed for a given use case in terms of the combinations involved, and how those resources are assembled and relied on (for example, targeted customer segments, specific technology portfolios, or contracted resource groupings)?

3. Which institution is accountable for which decision? (e.g., distributors for local capacity adequacy; the IESO for energy dispatch and system-wide optimization)

This enables distributors to procure capacity-oriented services and verify performance using shared tools while the IESO retains energy market operation and balancing. Where dual participation is needed, interfaces can be specified explicitly rather than assumed.

This approach is consistent with the phased, "simplified DSO model" articulated in the OEB DSO Capabilities report[8]: build the minimum viable capabilities needed to act on near-term opportunities, while avoiding early commitments that prejudge the eventual institutional structure.

[8] Ontario Energy Board, *Distribution System Operator Capabilities*, Discussion Paper, EB-2025-0060 (May 2025), online (pdf): OEB <engagewithus.oeb.ca/44842/widgets/188155/documents/152950>.

7.5. Shared services as a hedge against uncertainty, not a shortcut to markets

Shared services can be a hedge against uncertainty, rather than a shortcut to market sophistication. Cybersecurity operations, data governance, analytics, and even elements of customer engagement and aggregation support can be pooled across distributors to reduce duplication and manage risk. None of these functions require, or imply, that distributors must also act as market facilitators.

Seen in this light, the most durable contribution of the Roadmap may lie not in its preferred end state, but in its insistence that Ontario stop treating coordination capability as an abstract future requirement. The challenge for regulators is to ensure that the means — shared platforms and services — do not quietly determine the ends by embedding market authority before the economic and institutional case has been made.

The guiding principle should therefore be simple: build platforms that enable coordination first and decide later — on the basis of evidence — where markets are truly warranted.

8. POLICY DIRECTION, ADJUDICATION, AND THE NEED FOR REGULATORY PACE TO KEEP UP

8.1. The OEB's dual role: policy development and adjudication

A further reason for caution before convergence lies in the institutional structure of the OEB itself. The OEB operates with a deliberate separation between its policy-setting functions — including guidelines, frameworks, consultations, and staff-led reports — and its adjudicative role, exercised by commissioners through contested proceedings and reasoned decisions.

Recent policy instruments — the NWS Guidelines, BCA Framework, DSO Capabilities consultation, and related innovation initiatives[9] — signal a clear direction: lower barriers to DERs, require proportional NWS consideration, and strengthen coordination. They are necessary enablers, but they do not replace adjudicative determinations on cost recovery, authority, and accountability.

Policy direction alone is not determination. Commissioners must decide contested cases on evidence; end-state claims that ignore this risk overstating the feasible pace of institutional change.

8.2. Provincial priorities matter — but they do not substitute for adjudication

The momentum behind DSO concepts is also reinforced by broader provincial government priorities: electrification, reliability, affordability, economic growth, and decarbonization. These priorities are expressed through ministerial directives, long-term planning frameworks, and funding programs that emphasize flexibility, demand-side resources, and efficient use of infrastructure.

The Roadmap aligns well with these objectives, particularly in its focus on enabling DER participation and avoiding unnecessary capital investment. That alignment strengthens the Roadmap's policy relevance. But alignment with government priorities does not eliminate the need for careful regulatory sequencing. The OEB's statutory role is not to implement policy preferences directly, but to translate them into outcomes through evidence-based decisions that withstand scrutiny.

This distinction is especially important in the DSO context, where changes to roles, market authority, and coordination responsibilities would have far-reaching implications for cost allocation, risk assignment, and customer outcomes.

8.3. Why adjudicative pace — not policy ambition — sets the real tempo

From the perspective of Commissioners, the challenge is not whether DSOs are conceptually attractive, but whether specific proposals can be decided, justified, and defended within the confines of an adjudicative record. Decisions must be grounded in demonstrable need, clear statutory authority, and evidence of net benefit to customers. They should aim to be sufficiently generalizable to serve as informative frameworks for policy discretion, rather than bespoke accommodations for early movers.

[9] Ontario Energy Board, *OEB Innovation Sandbox*, online: OEB <oeb.ca/_html/sandbox/index.php>.

Once proposals move from externally funded pilots to rate-funded programs, the conversation changes materially. The questions that matter in adjudication are not whether an approach aligns with policy objectives, but whether it can be justified in comparison to alternatives, supported by evidence, and relied on to inform decisions in the specific circumstances of a case. In that setting, ambitions about end states tend to meet very concrete tests around scope, cost, accountability, and risk allocation.

This is why the pace of adjudication often becomes the binding constraint — not because of resistance to change, but because institutional decisions have to be durable once made. Moving too quickly to define roles or authority can narrow options before the evidence base is strong enough to support them.

8.4. The value of guidelines as "enablers," not substitutes

Seen in this light, the OEB's recent policy instruments serve an important but bounded role. Guidelines and frameworks are enablers: they clarify expectations, reduce friction, and create space for experimentation. They are not substitutes for adjudication, nor are they mandates for specific institutional forms.

Focusing on capabilities, feasibility, and proportionality supports the adjudicative process rather than preempts it, allowing evidence to accumulate before asking for broad change.

8.5. Keeping policy, government direction, and adjudication aligned

The risk, therefore, is not that the OEB will fail to act, but that policy ambition, sector advocacy, and government priorities move faster than the adjudicative machinery can responsibly follow. When this happens, pressure builds for regulatory shortcuts: endorsing end states "in principle," embedding assumptions in platforms or codes, or allowing early decisions to harden into de facto regulatory policy.

A more durable approach keeps roles aligned but distinct:

- Government articulates priorities and long-term objectives.
- OEB policy creates frameworks that enable innovation and learning.
- OEB adjudication determines, case by case, which tools, roles, and authorities are justified.

8.6. Implications for the DSO debate

Applied to the DSO question, this perspective reinforces the case for restraint. The issue is not whether Ontario will need stronger distribution-level coordination — it will — but whether the evidentiary record is yet sufficient for Commissioners to endorse a Market Facilitator DSO as the default institutional form.

Until that record exists, the most constructive role for policy-makers and sector leadership is to feed the adjudicative pipeline with credible, well-bounded cases, rather than to seek early endorsement of an untested end state.

8.7. Moving beyond pilots means entering the adjudicative arena

A recurring argument advanced by distributors is that Ontario must "move beyond pilots." As a statement of intent, this is uncontroversial. As a regulatory proposition, it has a precise and demanding meaning.

Most flexibility-related pilots over the past several years have been supported by external funding — through innovation challenges, government programs, or system-level innovation funds. These pilots have been valuable in surfacing technical, operational, and customer-engagement insights. But critically, they have required little if any adjudicative review, and the business case has been conditional on the third-party funding. They have not been fully funded through rates, nor tested against the evidentiary standards that typically apply when distributors seek to recover costs from customers.

In practice, moving beyond pilots has meant something quite specific: shifting from learning under external funding to proposing initiatives that rely on ratepayer support. That shift brings different evidentiary expectations, and experience suggests it is often where otherwise promising concepts are most rigorously tested.

Moving beyond pilots is to change the regulatory footing of these activities. Once distributors propose to fund flexibility programs, platforms, or markets with ratepayer dollars, they must bring those proposals before the OEB. At that point, the relevant question is no longer whether an approach is innovative or aligned with policy objectives, but whether it meets the evidentiary tests required for approval: demonstrated need, proportionality, cost-effectiveness, clear accountability, and net benefit to customers.

This distinction matters because pilots are, by design, insulated from the full discipline of adjudication. They allow learning under conditions of reduced risk and simplified governance. Adjudicated programs do not. They must be justified in comparison to alternatives, subjected to cross-examination, and capable of informing reasoned decisions. The burden shifts decisively onto the proponent.

From this perspective, calls to move beyond pilots need to acknowledge the central role of adjudication: the transition from pilot to program is not a matter of confidence or readiness; it is a matter of evidence. In this sense, adjudication is not a brake on momentum but the mechanism through which momentum becomes durable.

For Commissioners, that means sequencing matters. Pilots can inform judgment, but institutionalized roles and rate-funded programs require a record robust enough to withstand scrutiny and meaningfully inform panel deliberations.

9. A CONSTRUCTIVE PATH FORWARD: CAPABILITY FIRST, ORTHODOXY LATER

9.1. Retaining what the Roadmap gets right

A constructive response to the Roadmap begins by retaining its strongest elements: phased progression, readiness assessment, shared services, workforce capability, and attention to governance and cybersecurity. These foundations matter regardless of how the DSO question ultimately resolves.

Equally important is the roadmap's recognition that Ontario's distributors are heterogeneous. Differences in size, system topology, DER penetration, and organizational capacity mean that a one-size-fits-all implementation path would be both inefficient and inequitable. Any credible path forward must therefore allow for differentiated adoption speeds while preserving system-wide coherence where it matters most.

9.2. What should remain explicitly open

Caution is warranted in the transition from capability development to institutional prescription. Three questions, in particular, should remain explicitly open in the near term.

First, how local coordination is executed. Whether a given need is best met through programmatic incentives, bilateral contracts, operating envelopes, auctions, or some hybrid approach should be determined by the nature of the need, the economics of the solution, and the number of credible providers — not by a presumption that markets are the default solution.

Second, where price formation occurs. Energy price formation and system-wide optimization remain the core responsibility of the IESO. Introducing local price signals may be useful in some contexts, but doing so raises questions about interaction effects, accountability, and dispute resolution that should be addressed through evidence and testing rather than assumption.

Third, how local and bulk-system signals are reconciled. Dual participation, residual flexibility, and coordination under constrained conditions all require carefully designed interfaces. These interfaces can be explored through sandbox testing, tabletop exercises, and targeted pilots without committing to permanent market authority at the distribution level.

Keeping these questions open is not indecision; it is disciplined sequencing. Nothing in this approach precludes a Market Facilitator DSO where evidence supports it; it simply avoids assuming that outcome in advance of an adjudicated evidentiary record and decision.

9.3. A capability-first regulatory posture

A capability-first posture offers a practical way to reconcile momentum with caution. Under such an approach, the regulator would require distributors to demonstrate competence in a defined set of functional areas — planning integration, customer targeting, data access and visibility, operational procedures, and performance verification — before granting additional authority. Evidence, rather than aspiration, would determine when and where more complex coordination approaches are warranted.

This posture aligns with existing guidelines and frameworks in Ontario. The NWS Guidelines, BCA Framework, and DSO Capabilities consultation emphasize demonstrated need, feasibility, and proportionality — what distributors must be able to do, not a single end state.

9.4. Conditional decisions instead of binary choices

One of the implicit pressures in the DSO debate is the perception that Ontario must choose between decisive convergence and indefinite delay. In practice, regulators have a wider menu of options. Conditional decisions — authorizing specific activities subject to defined evidentiary thresholds — are a familiar and effective regulatory tool.

Applied here, this could mean endorsing shared platforms and services, approving targeted pilots where markets appear promising, and setting criteria that must be met before broader market-facilitation authority is granted, such as economic durability, sufficient participation, interoperability, and clear accountability.

9.5. Reframing the central question

The most productive way to reframe the DSO debate is to shift the focal question. Instead of asking "Which DSO model should Ontario adopt?", regulators and stakeholders might ask: "Which coordination problems must be solved, through which portfolios of customer-sited resources, and by which accountable institution?" This reframing keeps attention on outcomes — reliability, affordability, and system efficiency — rather than on institutional labels.

From this perspective, market facilitation becomes one possible tool among many, rather than the defining feature of a future DSO. It may prove appropriate in some contexts and unnecessary in others. The task of regulation is not to pick the winner in advance, but to ensure that whatever level of coordination is required is justified by evidence and aligned with clear accountability.

Ontario can move decisively on capability building, shared services, and governance reform while postponing firm decisions about market form until economics and institutional interfaces are better understood. This respects the Roadmap's leadership without allowing early advocacy to harden prematurely into architecture.

10. CONCLUSION: CAPABILITY BEFORE COMMITMENT

The Roadmap arrives at a moment when Ontario's electricity system is under real pressure to adapt. Its call for momentum is understandable, and many of its recommendations — particularly those related to phased readiness, shared services, workforce development, and governance discipline — are timely and well founded.

There is an argument to be made, however, that the Roadmap's call for early commitment to a specific DSO market form is premature. The core issue is not whether Ontario should enhance distribution-level coordination, but how that coordination should be structured, sequenced, and governed. DER economics are often thin, highly contextual, and sensitive to assumptions; in such conditions, market facilitation should be treated as a tool to test in bounded settings — not as an organizing principle.

Institutional clarity matters as much as economic realism. Ontario's longstanding separation between bulk-system energy management and local network capacity responsibility has served the system well. Blurring this boundary through early assignment of market-clearing or dispatch-adjacent authority at the distribution level risks creating ambiguity precisely where accountability must be most robust. The challenge is not intent or competence, but durability under stress.

A more resilient path forward is therefore capability-first. Ontario can move decisively to build the functions required to plan for, procure, and operate non-wires solutions — data visibility, customer targeting, operational procedures, performance verification, and secure interfaces — without predetermining the eventual market form. Shared platforms and services should be designed to enable coordination across a range of acquisition models, not to embed market authority by default. Conditional decisions, phased permissions, and clear evidentiary thresholds can provide momentum without locking in.

Reframed this way, the central question is not "Which DSO model should Ontario adopt?" but "Which coordination problems must be solved, with which coordination approach, and by which accountable institution?" Answering that question requires patience as well as resolve. It requires regulators to move more slowly than advocates, not out of caution for its own sake, but to preserve optionality while learning accumulates.

The Roadmap is best read in this spirit: not as a destination, but as a well-argued proposal that sharpens the regulator's questions before it narrows the regulator's choices. ■